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State of the Market Report for PJM

Monitoring Analytics, LLC

Independent
Market Monitor
for PJM

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2023

Preface

The PJM Market Monitoring Plan provides:

> The Market Monitoring Unit shall prepare and submit contemporaneously to the Commission, the State Commissions, the PJM Board, PJM Management and to the PJM Members Committee, annual state-of-the-market reports on the state of competition within, and the efficiency of, the PJM Markets, and quarterly reports that update selected portions of the annual report and which may focus on certain topics of particular interest to the Market Monitoring Unit. The quarterly reports shall not be as extensive as the annual reports. In its annual, quarterly and other reports, the Market Monitoring Unit may make recommendations regarding any matter within its purview. The annual reports shall, and the quarterly reports may, address, among other things, the extent to which prices in the PJM Markets reflect competitive outcomes, the structural competitiveness of the PJM Markets, the effectiveness of bid mitigation rules, and the effectiveness of the PJM Markets in signaling infrastructure investment. These annual reports shall, and the quarterly reports may include recommendations as to whether changes to the Market Monitoring Unit or the Plan are required.[1]

Accordingly, Monitoring Analytics, LLC, which serves as the Market Monitoring Unit (MMU) for PJM Interconnection, L.L.C. (PJM), and is also known as the Independent Market Monitor for PJM (IMM), submits this *2023 Quarterly State of the Market Report for PJM: January through March*.[2] [3]

1 PJM Open Access Transmission Tariff (OATT) Attachment M (PJM Market Monitoring Plan) § VI.A. Capitalized terms used herein and not otherwise defined have the meaning provided in the OATT, PJM Operating Agreement, PJM Reliability Assurance Agreement (RAA), the Consolidated Transmission Owners Agreement (CTOA) or other tariffs that PJM has on file with the Federal Energy Regulatory Commission (FERC or Commission).
2 OATT Attachment M.
3 All references to this report should refer to the source as Monitoring Analytics, LLC, and should include the complete name of the report: *2023 Quarterly State of the Market Report for PJM: January through March*.

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Introduction

Q1 2023 in Review

Reliability is a core goal of PJM. Maintaining and improving competitive markets should also be a core goal of PJM. The goal of competition in PJM is to provide customers reliable wholesale power at the lowest possible price, but no lower. The PJM markets have done that. The PJM markets work, even if not perfectly. The results of PJM markets were reliable in the first three months of 2023. The results of Winter Storm Elliott in December 2022 continue to reveal significant market design issues in the capacity market. The markets also face a challenge from high levels of generator retirements, with no clear source of replacement capacity. The results of the energy market were competitive in the first three months of 2023. As a result of FERC's resolving a core underlying issue in the capacity market, the overstated market seller offer cap, the results of the 2024/2025 capacity auction were competitive. The PJM markets bring customers the benefits of competition when the market rules allow competition to work and prevent the exercise of market power.

Markets provide incentives for innovation and efficiency. Organized, competitive wholesale power markets are the best way to facilitate the least cost path to decarbonization. Renewables can compete, without guaranteed long term contracts. New entrant solar and wind resources are now competitive with existing coal resources in PJM. Innovation will occur in renewable technologies in unpredictable and beneficial ways. But the PJM markets are not perfect. Significant changes to the market design continue, including some that improve markets and some that do not. Significant issues with the market design remain. It is not guaranteed that the market design will successfully adapt to the changing realities, including the role of renewable and intermittent resources, the role of distributed resources, the role of regulated EDCs in competitive wholesale power markets, and the role of states and the federal government in subsidizing resources and in environmental regulation.

One of the key challenges facing the market is the high level of expected resource retirements between now and 2030 with no clear source of replacement capacity. Although the exact numbers may vary, an estimated total of 51,757 MW of capacity are at risk of retirement, consisting of 6,628 MW currently planning to retire, 23,509 MW expected to retire for state and federal environmental regulatory reasons, and 21,621 MW expected to be uneconomic. The retiring capacity consists primarily of coal steam plants and CTs. If the units at risk are replaced by new gas-fired CCs, those new units will require a significant amount of firm gas pipeline capacity. The new CC plants would require more than two BCF/day of firm pipeline capacity. It is not clear that adequate pipeline capacity is available or will be available under the current regulatory framework for gas pipelines.

This level of retirements is not unprecedented. Retirements during the 12 year period from 2011 to 2022 were 47,492.0 MW, comparable to the retirements expected over the next eight years, although the annual rate of currently expected retirements is higher. But the current challenge associated with replacing retiring resources is more significant than the issues faced in PJM over the past 12 years. Given current technology and the short time period, the retiring capacity can only be replaced by gas-fired generation, or largely replaced by gas-fired generation. Renewables can replace a significant amount of the energy output but cannot replace the capacity. Capacity means that the resource is expected to be available when needed, regardless of the time of day or ambient conditions. While all resource types have forced outages, solar resources will not be available when the sun is not shining and wind resources will not be available when the wind is not blowing, regardless of derating values. But, given current constraints on the gas pipeline system, the potential sources of the more than two BCF/day are not clear. It is essential that FERC, the states, PJM, PJM stakeholders and all segments of the gas industry (transportation, storage and commodity) address the issues of firm gas availability.

Of the 12,761.4 MW of combined cycle projects in the queue, 7,902.6 MW (61.9 percent) are expected to go in service based on historical completion rates as of March 31, 2023, providing both energy and capacity at that level. Of the 215,812.0 MW of renewable projects in the queue, only 29,880.4 MW (13.9 percent) are expected to go in service based on historical completion rates and be available to supply energy. Of those 29,880.4 MW, only 13,592.2 MW (6.3 percent of the total) are expected to be capacity resources, based on the average derate factors for storage, wind and solar.

In addition to the need to identify sources of firm gas for new resources, the steadily increasing role of gas fired generation and the declining role of coal highlight the importance of ensuring that PJM has real time, detailed and complete information on the gas supply arrangements of all generators, that PJM consider rules requiring capacity resources to have firm fuel supplies and that PJM evaluate the extent to which new gas-fired generators will have access to firm gas. It is also essential that FERC consider and address the implications of the inconsistencies between the gas pipeline business model and the power producer business model and the issue of market power in the gas commodity markets under extreme weather conditions. PJM will rely on existing and new gas-fired generation in the foreseeable future and it is essential that such resources have the gas supply arrangements that will permit them to provide reliability and flexibility and competitive offers.

Markets exist in a broader regulatory environment that creates significant constraints for markets. The simple fact is that the sources of new capacity that could fully replace the retiring capacity have not been clearly identified. That task is a complex one and includes significant factors outside the market design, including state and federal environmental policies and siting decisions. While market signals are essential, market signals alone cannot resolve some of the nonmarket constraints.

The solution to nonmarket constraints is not a return to cost of service regulation, either in whole or in part. The temptation to dictate solutions and require customers to pay cost of service rates is strong. Examples include paying some generators cost of service rates to provide reserves, or expanding the definition of RMR contracts beyond transmission reliability. But dictating solutions has unintended consequences. Planners are seldom correct. Creating a separate class of generators who receive cost of service revenues would be discriminatory and undercut a fundamental part of the PJM self sustaining market design.

Markets should not make the transition more difficult. Given the nonmarket regulatory constraints, a goal of market design should be to be consistent and predictable. A consistent and predictable design would provide a stable investment environment for generators and a stable price environment for customers who both consume and invest. The objective of the market design should be markets that work, markets that work for generators and markets that work for customers. Abstract discussions of incentives and penalties have led some to the conclusion that if high prices provide incentives at times, then even higher prices or higher penalties are better incentives. One of the lessons of the winter storms Uri and Elliott, in very different market designs, is that extreme prices and penalties do not have the intended incentive effect and do have a destructive effect, in the energy market and in the capacity market. There is no reason to bankrupt generators or force generators into early retirement. There is no reason to bankrupt customers or impose impossible bills on customers. There is no reason to permit the exercise of market power. Market incentives can and do work but the incentive design should make markets more workable rather than riskier and less workable.

The PJM capacity market has played a central role in the evolution of the self sustaining overall PJM market design. If PJM markets are going to continue to be sustainable, it is essential that the basic design of the current capacity market remain. The goal of any changes to the capacity market design should be explicitly and demonstrably to improve the competitiveness of the market so that the capacity market can continue to use competitive forces to contribute to the success of the energy market, at the lowest possible cost.

Addressing issues in the capacity market design is an important part of the solution to the reliability issues. There are longstanding issues with the capacity market that continue to be ignored. In addition to the fact that the Capacity Performance (CP) design is a failed experiment, the issues include the role of intermittents, uniform application of the must offer rule, ensuring the comparable treatment of thermal and intermittent resources, and ensuring the comparable treatment of demand side and energy efficiency resources as market resources.

The challenge is to create a straightforward capacity market design that meets the simple objectives of a capacity market and that does not become a vehicle for energy market incentives or rent seeking or attempts to limit the ways in which specific types of generation participate in PJM markets. Energy market incentives should remain in the energy market.

The only purpose of the capacity market is to make the energy market work. That means two specific things. The capacity market needs to define the total MWh of energy that are needed to reliably serve load in all hours. The capacity market needs to provide the missing money; the capacity market needs to allow all cleared capacity resources the opportunity to cover their net avoidable costs on an annual basis to ensure the economic sustainability of the reliable energy market. Capacity is not a thing. Capacity does not power light bulbs or refrigerators or air conditioners. The only real product provided in wholesale power markets is energy. The capacity market is an administrative construct designed with these two purposes.

The answer is not to make the penalties higher. The answer is not to make the penalties lower. The answer is not to raise the market seller offer cap and permit the exercise of market power. The answer is not to increase or distort the risk component of offers. The answer is not to weaken performance requirements including unit parameters. The answer is not to make the capacity market design even more complicated. The answer is to return to the basic purpose of the capacity market, including ensuring that capacity resources are paid only when available to provide energy. The capacity market design should be as simple as possible.

Winter Storm Elliott highlighted significant issues with the current (CP) capacity market design. There is no reason that in a rational market design less than 24 hours of cold weather should result in a crisis and a level of administrative complexity that threatens to undermine the incentives to invest in existing and new supply resources at a time when those resources are needed. Payment of up to two billion dollars in penalties and penalties that can exceed three times the annual capacity revenue for specific units do not provide useful incentives. PJM's request to lengthen the payment period for penalties in order to prevent bankruptcies is further evidence of the significance of the issue. The CP design undermines incentives rather than creating positive incentives to invest and perform. The goal should be to never repeat the results of Elliott.

Winter Storm Elliott provided the first real test of the CP design. Elliott showed that the CP design does not provide effective incentives. There was an extremely high forced outage level during Elliott despite the penalties and despite the fact that the effectively uncapped market seller offer cap (MSOC) was in place (Net CONE times B) for RPM auctions conducted for the 2022/2023 Delivery Year. In addition, it has been clear from prior, very brief and local PAI events that the process of defining excuses and retroactive replacement transactions is complex and very difficult to administer, not well defined, and includes substantial subjective elements. The energy market clearing, in contrast, is transparent and efficient and timely. While there are issues with the details of energy market pricing that must be addressed, including shortage pricing, the energy market does not include or create the significant and long lasting uncertainty created by the PAI rules as exhibited most dramatically by the results of Elliott. The PAI design creates an administrative process that adds unacceptable uncertainty to the markets and that can never approach the effectiveness of the energy market in providing price signals and timely settlement.

The fundamental mistake of the CP design was to attempt to recreate energy market incentives in the capacity market. The CP model was an explicit attempt to bring energy market shortage pricing into the capacity market design. The CP model was designed on the assumption that shortage prices in the energy market were not high enough and needed to be increased via the capacity market. The CP design focused on a small number of critical hours (performance assessment hours or PAH, translated into five minute intervals as PAI) and imposed large penalties on generators that failed to produce energy only during those hours. But the use of capacity market penalties rather than energy market incentives created risk. While there are differences of opinion about how to value the risk, this CP risk is not risk that is fundamental to the operation of a wholesale power market. This is risk created by the CP design in order, in concept, to provide an incentive to produce energy during high demand hours that is even higher than the energy market incentive, amplified by an operating reserve demand curve (ORDC). The potential risk created by CP is not limited to risk for individual generators, but extends to the viability of the market. If penalties create bankruptcies that threaten the viability of required energy output from the affected units, there is a risk to the market.

The MMU recommends elimination of the key remaining components of the Capacity Performance model because they interfere with competitive outcomes in the capacity market and create unnecessary complexity and risk. The use of Net CONE to define the penalty rate is a form of arbitrary administrative pricing that creates high risk for generators, creates complexity in the calculation of the cost to mitigate risk (CPQR) and ultimately raises the price of capacity. Rather than penalizing capacity resources for nonperformance, capacity resources should be paid the daily price of capacity only to the extent that they are available to produce energy or provide reserves, as required by PJM on an hourly basis, based on their cleared capacity (ICAP). This is a positive performance incentive based on the market price of capacity rather than a penalty based on an arbitrary and incorrect assumption.

One of the benefits of competitive power markets is that changes in input prices and changes in the balance of supply and demand are reflected immediately in energy prices for both price decreases and price increases. Energy prices decreased in the first three months of 2023 from the first three months of 2022. The real-time load-weighted average LMP in the first three months of 2023 decreased by $23.85 per MWh, 44.1 percent, from the first three months of 2022, from $54.13 per MWh to $30.28 per MWh.

Of the $23.85 per MWh decrease, $14.15 per MWh (59.3 percent) was a result of the decreased costs of fuel, emissions allowances, and consumables, $3.35 per MWh (14.0 percent) was a result of the decrease in the sum of the markup, maintenance, and ten percent adder components of LMP, all of which reflect market power, $3.65 per MWh (15.3 percent) was a result of the decrease in the transmission constraint penalty factor component of LMP, and $0.50 per MWh (2.1 percent) was a result of the decrease in the scarcity component of LMP.

Both coal and natural gas prices were lower in the first three months of 2023 compared to the first three months of 2022. The real-time hourly average load in the first three months of 2023 decreased by 5.1 percent from the first three months of 2022, from 92,007 MWh to 87,311 MWh.

The total price of wholesale power decreased from $81.84 per MWh in the first three months of 2022 to $53.45 per MWh in the first three months of 2023, a decrease of 34.7 percent. Energy, capacity and transmission charges are the three largest components of the total price of wholesale power, comprising 96.6 percent of the total price per MWh in the first three months of 2023. Starting in the third quarter of 2019, the cost of transmission per MWh of wholesale power has been higher than the cost of capacity.

In the first three months of 2023, generation from coal units decreased 40.1 percent, generation from natural gas units increased 12.5 percent, and generation from oil decreased 11.9 percent compared to the first three months of 2022. Wind and solar output rose by 3.6 percent compared to the first three months of 2022, supplying 5.8 percent of PJM energy in the first three months of 2023.

Net revenue is a key measure of overall market performance as well as a measure of the incentive to invest in generation to serve PJM markets. Theoretical net revenues from the energy market decreased for all unit types in the first three months of 2023 compared to the first three months of 2022. Theoretical energy market net revenues decreased by 57 percent for a new combustion turbine (CT), 42 percent for a new combined cycle (CC), 89 percent for a new coal plant (CP), 41 percent for a new nuclear plant, 34 percent for a new onshore wind installation, 50 percent for a new offshore wind installation and 49 percent for a new solar installation.

Changes in forward energy market prices significantly affect the expected profitability of nuclear plants in PJM. Based on forward prices as of April 3, 2023, for energy, and known forward prices for capacity, all the nuclear plants in PJM are expected to cover their avoidable costs from energy and capacity market revenues in 2023, 2024, and 2025, without subsidies, with the exception of Davis Besse, a single unit nuclear plant, in 2023.

A number of PJM states are pursuing direct approaches to environmental issues including mandating the closure of emitting resources and capping emissions from existing and new resources, in addition to creating renewable portfolio standards (RPS). RECs (renewable energy credits) are an important mechanism used by many PJM states to implement environmental policy under a range of RPS approaches. RECs affect prices in the PJM wholesale power market. RECs provide out of market payments to qualifying renewable resources, primarily wind and solar, as well as some nonrenewable resources. Some resources are not economic without revenue from RECs.

In the absence of a PJM market carbon price, a single, transparent PJM market for RECs would contribute significantly to market efficiency and to the procurement of renewable resources in a least cost manner, if some or all of the PJM states with RPS decided to use that option. Ideally, there would be a single PJM operated forward market for RECs, for a single product based on a common set of state definitions of renewable technologies, with a single clearing price, trued up to real time delivery, that includes market power mitigation rules. The product definition is a state decision. States would continue to have the option to create separate RECs for additional products that did not fit the product definition, e.g. waste coal or trash incinerators. Such a market would provide better information for market participants about supply and demand and prices and contribute to a more efficient and competitive market and to better price formation. The market could also facilitate entry by renewable resources by reducing the risks associated with lack of transparent REC market data and ensuring competitive prices. But it is also important, given that PJM states have a range of approaches to climate policy, to not integrate the REC market into the PJM energy or capacity market so tightly that it affects the prices of energy and capacity for all market participants. Investors would have the responsibility to evaluate and manage their own strategies with a standalone REC market.

Despite suggestions that PJM needs a flexibility product, the PJM fleet already includes the flexibility needed to offset the fluctuations in output assumed to be inherent in renewable energy. PJM's combined cycle fleet offered an average of 38,566 of dispatchable MW in the energy market in the first three months of 2023. Gas fired combined cycles can provide significant flexibility if the market design and rules can account for their characteristics appropriately. Combustion turbines, which have flexible start times, offered another 40,570 of flexible MW in the first three months of 2023. PJM does not need a flexibility product. PJM needs to provide incentives to existing and new entrant resources to unlock the significant flexibility potential that already exists and to stop creating incentives for inflexibility. This means enforcing parameter limited schedules, enforcing must offer requirements, enhancing generator modelling to support combined cycle resources without weakening market power mitigation rules, enforcing the correct definition of maximum emergency status, and requiring resources to follow PJM's dispatch instructions in order to be eligible for uplift payments. There is no reason to consider a new flexibility product until the existing rules are enforced and refined, including the elimination of current incentives to be inflexible.

PJM interventions in the market have substantial effects on energy market outcomes. For example, fast start pricing, transmission line ratings, transmission penalty factors, load forecast bias, hydro resource schedules, and unit ramp rate adjustments change the dispatch of the system, affect prices, and can create significant price increases through transmission line limit violations or restrictions on the resources available to resolve constraints. PJM interventions to reduce line ratings unnecessarily trigger transmission constraint penalty factors and significantly increase power prices.

In the first three months of 2023, $0.75 per MWh (2.5 percent) of the real-time load-weighted LMP was the result of transmission constraint penalty factors. In the first three months of 2023, there were 686 violated transmission constraint intervals in the real-time market with a constraint limit less than 100 percent of the actual constraint limit. In the first three months of 2023, among the constraints with reduced constraint limits, the constraint limit was reduced on average by 5.3 percent, below the level that PJM used in actual operations. PJM should limit its interventions in the market and provide greater transparency about the reasons and impacts, if any such interventions continue, in order to enhance market efficiency. PJM's actions should be defined by rules and should be transparent. The MMU continues to recommend that PJM end the practice of discretionary reductions in transmission line ratings modeled in the market clearing and included in LMP.

Fast start pricing significantly increases energy market prices in ways not consistent with competitive markets. Fast start pricing creates an inefficient wedge between the competitive price and the actual price paid to generators and charged to customers. Fast start pricing increased average real-time energy market prices in the first three months of 2023 by 2.9 percent compared to competitive energy market prices. This is a significant increase to energy prices given that it does not result from any change to the underlying market supply and demand fundamentals.

The competitiveness of energy market prices cannot be taken for granted. In 2022, 3.6 percent of marginal units set price with positive markups despite failing the Three Pivotal Supplier (TPS) test for market power in the real-time energy market. This was the result of documented flaws in the application of offer capping when units fail the TPS test. PJM also schedules and pays uplift to units that fail the TPS test and to units during emergency and weather alert conditions without requiring that units use flexible operating parameters, an issue that FERC raised in a June 17, 2021, Order to Show Cause. A straightforward solution proposed by the MMU would remove crossing price-based and cost-based offer curves and replace any inflexible parameter with its approved parameter limited value for all resources failing the TPS test. This solution would also reduce the computational time of the day-ahead market, a goal which PJM seeks to achieve by oversimplifying the process by which it evaluates the price-based offer and cost-based offer. PJM's solution would exacerbate the identified issues with the application of the market power mitigation rules. The consistency and frequency of TPS test checks for market power should also be examined. Market power goes unmitigated because units are not tested again after their initial commitment even if system conditions and dispatch needs change. The rules should ensure that all resources committed in the day-ahead and real-time markets are evaluated for market power.

In addition to the existing issues with market power mitigation, the current tariff definition of a competitive energy offer results in overstated cost-based offers through the inclusion of major maintenance costs which do not vary in the short run with energy output and are not short run marginal costs. Further, the use of and applicability of fuel cost policies have been undermined. Fuel cost policies should ensure that the costs in generator offers are clearly defined and are verifiable and systematic. Fuel cost policies are required for effective and accurate market power mitigation. Some generation owners prefer to not have clearly defined costs in order to exercise market power and in order to avoid taking responsibility for the accuracy of their offers.

The evolution of wholesale power markets is far from complete. The PJM markets need rules in order to provide reliable energy through competition. The foundational principle of using markets, with rules to prevent the exercise of market power and provide competitive results, is essential. Private investors, regardless of technology or subsidies, will put capital at risk and earn compensatory returns in markets that are not skewed in favor of any specific technology. The core elements of the PJM market design remain robust. The use of locational marginal prices (LMP) in the energy market and locational prices in the capacity market continue to be essential to getting the price signals right. Technological and policy changes do not require that the core elements change. But the market design can be improved and made more reliable and more efficient and more competitive. The markets will also need support from regulators whose decisions create and/or limit the options available to investors in PJM resources. PJM and its market participants will need to continue to resist the temptation to turn to solutions based on cost of service rather than markets. PJM and its market participants will need to continue to work constructively to refine the competitive market design and to ensure the continued effectiveness of PJM markets in providing customers wholesale power at the lowest possible price, but no lower.

PJM Market Summary Statistics

Table 1-1 shows selected summary statistics describing PJM markets.

Table 1-1 PJM market summary statistics: January through March, 2022 and 2023[1]

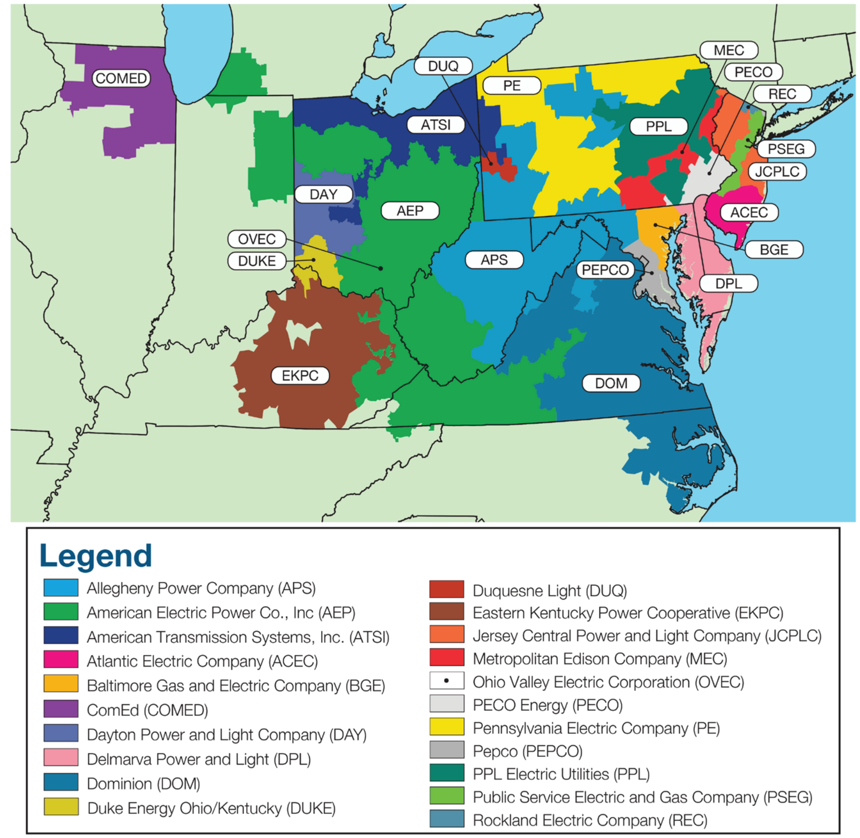
	(Jan-Mar) 2022	(Jan-Mar) 2023	Percent Change
Average Hourly Load Plus Exports (MWh)	98,417	93,209	(5.3%)
Average Hourly Generation Plus Imports (MWh)	100,535	94,971	(5.5%)
Peak Load Plus Export (MWh)	130,779	123,504	(5.6%)
Installed Capacity at March 31 (MW)	185,769	183,312	(1.3%)
Load Weighted Average Real Time LMP ($/MWh)	$54.13	$30.28	(44.1%)
Total Congestion Costs ($ Million)	$510.3	$175.5	(65.6%)
Total Uplift Credits ($ Million)	$28.2	$19.6	(30.5%)
Total PJM Billing ($ Billion)	$18.10	$12.03	(33.5%)

PJM Market Background

The PJM Interconnection, L.L.C. (PJM) operates a centrally dispatched, competitive wholesale electric power market that, as of March 31, 2023, had installed generating capacity of 183,312 megawatts (MW) and 1,116 members including market buyers, sellers and traders of electricity in a region including more than 65 million people in all or parts of 13 states (Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia) and the District of Columbia (Figure 1-1).[2] [3] [4]

As part of the market operator function, PJM coordinates and directs the operation of the transmission grid and plans transmission expansion improvements to maintain grid reliability in this region.

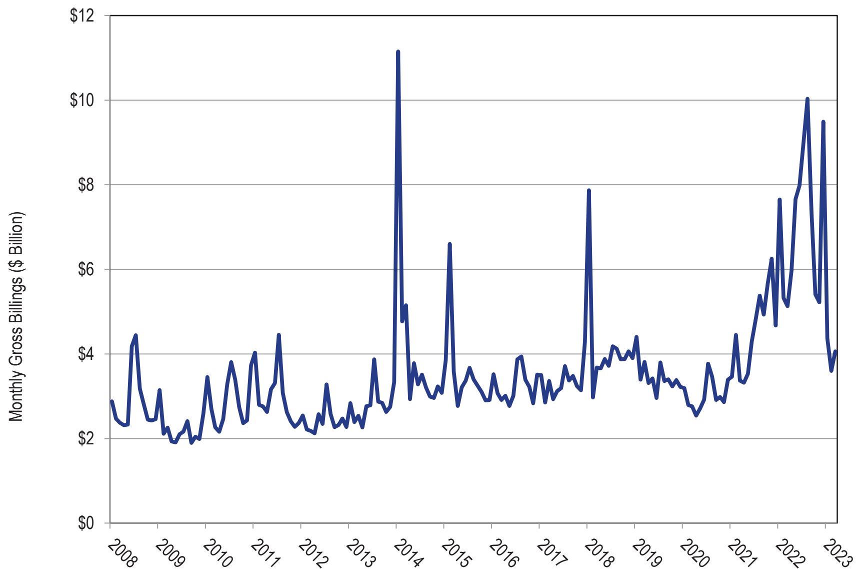
Figure 1-1 PJM's footprint and its 21 control zones



1 In Table 1-1, the MMU uses Total PJM Billing values provided by PJM. For 2019 and after, the Total PJM Billing calculation was modified to better reflect PJM total billing through the PJM settlement process.
2 See PJM. "Member List," which can be accessed at: <http://pjm.com/about-pjm/member-services/member-list.aspx>.
3 See PJM. "Who We Are," which can be accessed at: <http://pjm.com/about-pjm/who-we-are.aspx>.
4 See the *2022 State of the Market Report for PJM*, Volume II, Appendix A: "PJM Overview" for maps showing the PJM footprint and its evolution prior to 2022.

In the first three months of 2023, PJM had gross billings of $12.03 billion, a decrease of 33.5 percent from $18.10 billion in the first three months of 2022. (Figure 1-2).

Figure 1-2 PJM reported monthly billings ($ Billion): January 2008 through March 2023[5]



PJM operates the day-ahead energy market, the real-time energy market, the capacity market, the regulation market, the synchronized reserve market, the secondary reserve market and the financial transmission rights (FTRs) markets.

PJM introduced energy pricing with cost-based offers and market-clearing nodal prices on April 1, 1998, and market-clearing nodal prices with market-based offers on April 1, 1999. PJM introduced the Daily Capacity Market on January 1, 1999, and the Monthly and Multimonthly Capacity Markets for the January through May 1999 period. PJM implemented FTRs on May 1, 1999. PJM implemented the day-ahead energy market and the regulation market on June 1, 2000. PJM modified the regulation market design and added a market in Synchronized Reserve on December 1, 2002. PJM introduced an Auction Revenue Rights (ARR) allocation process and an associated Annual FTR Auction effective June 1, 2003. PJM introduced the RPM capacity market effective June 1, 2007. PJM implemented the DASR market on June 1, 2008, and eliminated it on October 1, 2022. PJM introduced the Capacity Performance capacity market design effective on August 10, 2015, with the Base Residual Auction for 2018/2019.[6 7]

5 In Figure 1-2, the MMU uses Total PJM Billing values provided by PJM. For 2019 and after, the Total PJM Billing calculation was modified to better reflect PJM total billing through the PJM settlement process.

Conclusions

This report assesses the competitiveness of the markets managed by PJM in the first three months of 2023, including market structure, participant behavior and market performance. This report was prepared by and represents the analysis of the Independent Market Monitor for PJM, also referred to as the Market Monitoring Unit or MMU.

For each PJM market, the market structure is evaluated as competitive or not competitive, and participant behavior is evaluated as competitive or not competitive. Most important, the outcome of each market, market performance, is evaluated as competitive or not competitive.

The MMU also evaluates the market design for each market. The market design serves as the vehicle for translating participant behavior within the market structure into market performance. This report evaluates the effectiveness of the market design of each PJM market in providing market performance consistent with competitive results.

Market structure refers to the cost, demand, and ownership structure of the market. The three pivotal supplier (TPS) test is the most relevant measure of market structure because it accounts for the ownership of assets and the

6 See also the *2022 State of the Market Report for PJM*, Volume II, Appendix A: "PJM Overview."

7 Analysis of 2023 market results requires comparison to prior years. During calendar years 2004 and 2005, PJM conducted the phased integration of five control zones: COMED, American Electric Power (AEP), The Dayton Power & Light Company (DAY), Duquesne Light Company (DUQ) and Dominion (DOM). In June 2011, PJM integrated the American Transmission Systems, Inc. (ATSI) Control Zone. In January 2012, PJM integrated the Duke Energy Ohio/Kentucky (DUKE) Control Zone. In June 2013, PJM integrated the Eastern Kentucky Power Cooperative (EKPC). In December 2018, PJM integrated the Ohio Valley Electric Corporation (OVEC.) By convention, control zones bear the name of a large utility service provider working within their boundaries. The nomenclature applies to the geographic area, not to any single company. For additional information on the integrations, their timing and their impact on the footprint of the PJM service territory prior to 2023, see *2022 State of the Market Report for PJM*, Volume 2, Appendix A: "PJM Overview."

relationship among the pattern of ownership, the resource costs, and the market demand using actual market conditions with both temporal and geographic granularity. Market shares and the related Herfindahl-Hirschman Index (HHI) are also measures of market structure.

Participant behavior refers to the actions of individual market participants, also sometimes referred to as participant conduct.

Market performance refers to the outcomes of the market. Market performance results from the behavior of market participants within a market structure, mediated by market design.

Market design means the rules under which the entire relevant market operates, including the software that implements the market rules. Market rules include the definition of the product, the definition of short run marginal cost, rules governing offer behavior, market power mitigation rules, and the definition of demand. Market design is characterized as effective, mixed or flawed. An effective market design provides incentives for competitive behavior and permits competitive outcomes. A mixed market design has significant issues that constrain the potential for competitive behavior to result in competitive market outcomes, and does not have adequate rules to mitigate market power or incent competitive behavior. A flawed market design produces inefficient outcomes which cannot be corrected by competitive behavior.

Energy Market Conclusion

The Market Monitoring Unit (MMU) analyzed measures of market structure, participant conduct and market performance, including market size, concentration, pivotal suppliers, offer behavior, markup, and price. The MMU concludes that the PJM energy market results were competitive in the first three months of 2023.

Table 1-2 The energy market results were competitive

Market Element	Evaluation	Market Design
Market Structure: Aggregate Market	Partially Competitive	
Market Structure: Local Market	Not Competitive	
Participant Behavior	Competitive	
Market Performance	**Competitive**	**Effective**

- The aggregate market structure was evaluated as partially competitive because the aggregate market power test based on pivotal suppliers indicates that the aggregate day-ahead market structure was not competitive on 17.8 percent of days. The hourly HHI (Herfindahl-Hirschman Index) results indicate that the PJM aggregate energy market in the first three months of 2023 was, on average, unconcentrated by FERC HHI standards. The average HHI was 677 with a minimum of 575 and a maximum of 921. The baseload segment of the supply curve was unconcentrated. The intermediate segment of the supply curve was moderately concentrated. The peaking segment of the supply curve was highly concentrated. The fact that the average HHI is in the unconcentrated range does not mean that the aggregate market was competitive in all hours. As demonstrated for the day-ahead market, it is possible to have pivotal suppliers in the aggregate market even when the HHI level is not in the highly concentrated range. It is possible to have an exercise of market power even when the HHI level is not in the highly concentrated range. The number of pivotal suppliers in the energy market is a more precise measure of structural market power than the HHI. The HHI is not a definitive measure of structural market power.
- The local market structure was evaluated as not competitive due to the highly concentrated ownership of supply in local markets created by transmission constraints and local reliability issues. The results of the three pivotal supplier (TPS) test, used to test local market structure, indicate the existence of market power in local markets created by transmission constraints. The local market performance is competitive as a result of the application of the TPS test. Transmission constraints create the potential for the exercise of local market power. The goal of PJM's application of the three pivotal supplier test is to identify local market power and offer cap to competitive offers, correcting for structural issues created by local transmission constraints. There are, however, identified issues with the definition of cost-based offers and the application of market power mitigation to resources whose owners fail the TPS test that need to be addressed because unit owners can exercise market power even when they fail the TPS test.

- Participant behavior was evaluated as competitive because the analysis of markup shows that marginal units generally make offers at, or close to, their marginal costs in both the day-ahead and real-time energy markets, although the behavior of some participants both routinely and during periods of high demand represents economic withholding. The ownership of marginal units is concentrated. The markups of pivotal suppliers in the aggregate market and of many pivotal suppliers in local markets remain unmitigated due to the lack of aggregate market power mitigation and the flawed implementation of offer caps for resources that fail the TPS test. The markups of those participants affected LMP.
- Market performance was evaluated as competitive because market results in the energy market reflect the outcome of a competitive market, as PJM prices are set, on average, by marginal units operating at, or close to, their marginal costs in both day-ahead and real-time energy markets, although high markups for some marginal units did affect prices.
- Market design was evaluated as effective because the analysis shows that the PJM energy market resulted in competitive market outcomes. In general, PJM's energy market design provides incentives for competitive behavior and results in competitive outcomes. In local markets, where market power is an issue, the market design identifies market power and causes the market to provide competitive market outcomes in most cases although issues with the implementation of market power mitigation and development of cost-based offers remain. The role of UTCs in the day-ahead energy market continues to cause concerns. Market design implementation issues, including inaccuracies in modeling of the transmission system and of generator capabilities as well as inefficiencies in real-time dispatch and price formation, undermine market efficiency in the energy market. PJM resolved the problems with real-time dispatch and pricing effective November 1, 2021. The implementation of fast start pricing on September 1, 2021, undermined market efficiency by setting inefficient prices that are inconsistent with the dispatch signals.
- PJM markets are designed to promote competitive outcomes derived from the interaction of supply and demand in each of the PJM markets. Market design itself is the primary means of achieving and promoting competitive outcomes in PJM markets. One of the MMU's core functions is to identify actual or potential market design flaws.[8] The approach to market power mitigation in PJM has focused on market designs that promote competition (a structural basis for competitive outcomes) and on mitigating market power in instances where the market structure is not competitive and thus where market design alone cannot mitigate market power. FERC relies on effective market power mitigation when it approves market sellers to participate in the PJM market at market based rates.[9] In the PJM energy market, market power mitigation occurs primarily in the case of local market power. When a transmission constraint creates the potential for local market power, PJM applies a structural test to determine if the local market is competitive, applies a behavioral test to determine if generator offers exceed competitive levels and applies a market performance test to determine if such generator offers would affect the market price.[10] There are, however, identified issues with the application of market power mitigation to resources whose owners fail the TPS test that can result in the exercise of local market power even when market power mitigation rules are applied. These issues need to be addressed. FERC recognized these issues in its June 17, 2021 order.[11] Some units with market power have positive markups and some have inflexible parameters, which means that the cost-based offer was not used and that the process for offer capping units that fail the TPS test does not consistently result in competitive market outcomes in the presence of market power. There are issues related to the definition of gas costs includable in energy offers that need to be addressed. There are issues related to the level of maintenance expense includable in energy offers that need to be addressed. There are currently no market power mitigation rules in place that limit the ability to exercise market power when aggregate market conditions are tight and there are pivotal suppliers in the aggregate market. Aggregate market power needs to be addressed. Market design must reflect appropriate incentives for competitive behavior, the application of local market power mitigation

8 OATT Attachment M (PJM Market Monitoring Plan).
9 See *Refinements to Horizontal Market Power Analysis for Sellers in Certain Regional Transmission Organization and Independent System Operator Markets*, Order No. 861, 168 FERC ¶ 61,040 (2019); *order on reh'g*, Order No. 861-A; 170 FERC ¶ 61,106 (2020).
10 The market performance test means that offer capping is not applied if the offer does not exceed the competitive level and therefore market power would not affect market performance.
11 175 FERC ¶ 61,231 (2021).

needs to be fixed, the definition of a competitive offer needs to be fixed, and aggregate market power mitigation rules need to be developed. The importance of these issues is amplified by the rules permitting cost-based offers in excess of $1,000 per MWh.

Capacity Market Conclusion

The Market Monitoring Unit (MMU) analyzed market structure, participant conduct and market performance in the PJM Capacity Market, including supply, demand, concentration ratios, pivotal suppliers, volumes, prices, outage rates and reliability.[12] The conclusions are a result of the MMU's evaluation of the 2024/2025 Base Residual Auction. The 2024/2025 RPM Base Residual Auction was conducted in 2022, but the results were not posted until February 27, 2023, due to an issue with the DPL South reliability requirement.

Table 1-3 The capacity market results were competitive

Market Element	Evaluation	Market Design
Market Structure: Aggregate Market	Not Competitive	
Market Structure: Local Market	Not Competitive	
Participant Behavior	Competitive	
Market Performance	Competitive	Mixed

- The aggregate market structure was evaluated as not competitive. For almost all auctions held from 2007 to the present, the PJM capacity market failed the three pivotal supplier test (TPS), which is conducted at the time of the auction.[13] Structural market power is endemic to the capacity market.
- The local market structure was evaluated as not competitive. For almost every auction held, all LDAs have failed the TPS test, which is conducted at the time of the auction.[14]
- Participant behavior was evaluated as competitive in the 2024/2025 BRA after the Commission order addressed the definition of the market seller offer cap by eliminating the net CONE times B offer cap and establishing a competitive market seller offer cap of net ACR, effective September 2, 2021.[15] Market power mitigation measures were applied when the capacity market seller failed the market power test for the auction, the submitted sell offer exceeded the defined offer cap, and the submitted sell offer, absent mitigation, would increase the market clearing price.
- Market performance was evaluated as competitive based on the 2024/2025 Base Residual Auction after the Commission order eliminating the net CONE times B offer cap and establishing a competitive market seller offer cap of net ACR, effective September 2, 2021. Although structural market power exists in the capacity market, a competitive outcome can result from the application of market power mitigation rules.
- Market design was evaluated as mixed because while there are many positive features of the Reliability Pricing Model (RPM) design and the capacity performance modifications to RPM, there are several features of the RPM design which still threaten competitive outcomes. These include the definition of DR which permits inferior products to substitute for capacity, the replacement capacity issue, the definition of unit offer parameters, and the inclusion of imports which are not substitutes for internal capacity resources.
- As a result of the fact that the capacity market design was found to be not just and reasonable by FERC and a final market design had not been approved, the 2022/2023 Base Residual Auction was delayed and held in May 2021, and for a number of additional reasons, the 2023/2024 Base Residual Auction was delayed and held in June 2022, the 2024/2025 Base Residual Auction was delayed and held in December 2022, and first and second incremental auctions for the 2022/2023 through 2026/2027 Delivery Years are canceled if within 10 months of the revised BRA schedule.[16]

12 The values stated in this report for the RTO and LDAs refer to the aggregate level including all nested LDAs unless otherwise specified. For example, RTO values include the entire PJM market and all LDAs. Rest of RTO values are RTO values net of nested LDA values.

13 In the 2008/2009 RPM Third Incremental Auction, 18 participants in the RTO market passed the TPS test. In the 2018/2019 RPM Second Incremental Auction, 35 participants in the RTO market passed the test. In the 2023/2024 RPM Third Incremental Auction, 36 participants in the RTO passed the TPS test.

14 In the 2012/2013 RPM Base Residual Auction, six participants included in the incremental supply of EMAAC passed the TPS test. In the 2014/2015 RPM Base Residual Auction, seven participants in the incremental supply in MAAC passed the TPS test. In the 2021/2022 RPM First Incremental Auction, two participants in the incremental supply in EMAAC passed the TPS test. In the 2021/2022 RPM Second Incremental Auction, two participants in the incremental supply in EMAAC passed the TPS test. In the 2023/2024 RPM Third Incremental Auction, eight participants in MAAC passed the TPS test.

15 176 FERC ¶ 61,137 (2021), *order denying reh'g*, 178 FERC ¶ 61,121 (2022), *appeal pending*, EPSA, et al. v. FERC, Case No. 21-1214, et al. (DC Cir. 2022). The Commission recognized the market power problem and issued an order correcting the PJM tariff, eliminating the prior offer cap and establishing a competitive market seller offer cap set at net ACR, effective September 2, 2021.

16 174 FERC ¶ 61,036 (2021), 177 FERC ¶ 61,050 (2021), 177 FERC ¶ 61,209 (2021).

Synchronized Reserve Market Conclusion

The MMU analyzed measures of market structure, conduct and performance for the PJM Synchronized Reserve Market for the first three months of 2023.

Table 1-4 The synchronized reserve market results were competitive

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.

Secondary Reserve Market Conclusion

The MMU analyzed measures of market structure, conduct and performance for the PJM Secondary Reserve Market for the first three months of 2023.

Table 1-5 The secondary reserve market results were competitive

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 included by 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.

Regulation Market Conclusion

The MMU analyzed measures of market structure, conduct and performance for the PJM Regulation Market for the first three months of 2023.

Table 1-6 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 93.2 percent of the hours in the first three months of 2023.
- Participant behavior in the PJM Regulation Market was evaluated as competitive in the first three months of 2023 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.

FTR Auction Market Conclusion

The *2023 Quarterly State of the Market Report for PJM: January through March* focuses on the 2022/2023 Monthly Balance of Planning Period FTR Auctions, specifically covering January 1, 2023, through March 31, 2023. The Market Monitoring Unit (MMU) analyzed measures of market structure, participant conduct and market performance, including market size, concentration, offer behavior, and price. The MMU concludes that the PJM FTR auction market results were partially competitive in the first three months of 2023.

Table 1-7 The FTR auction markets results were partially competitive

Market Element	Evaluation	Market Design
Market Structure	Competitive	
Participant Behavior	Partially Competitive	
Market Performance	**Partially Competitive**	**Flawed**

- Market structure was evaluated as competitive. The ownership of FTR obligations is unconcentrated for the individual years of the 2022/2025 Long Term FTR Auction, the 2022/2023 Annual FTR Auction and each period of the Monthly Balance of Planning Period Auctions. The ownership of FTR options is moderately or highly concentrated for every Monthly FTR Auction period and moderately concentrated for the 2022/2023 Annual FTR Auction. Ownership of FTRs is disproportionately (75.2 percent) by financial participants. The ownership of ARRs is unconcentrated.
- Participant behavior was evaluated as partially competitive because ARR holders who are the sellers of FTRs are not permitted to participate in the market clearing.
- Market performance was evaluated as partially competitive because of the flaws in the market design. Sellers, the ARR holders, cannot set a sale price. Buyers can reclaim some of their purchase price after the market clears if the product does not meet a profitability target. The market resulted in a substantial shortfall in congestion payments to load and significant and unsupportable disparities among zones in the share of congestion returned to load. FTR purchases by financial entities remain persistently profitable in part as a result of the flaws in the market design.
- Market design was evaluated as flawed because there are significant and fundamental flaws with the basic ARR/FTR design. The FTR auction market is not actually a market because the sellers have no independent role in the process. ARR holders cannot determine the price at which they are willing to sell rights to congestion revenue. Buyers have the ability to reclaim some of the price paid for FTRs after the market clears. The market design is not an efficient or effective way to ensure that the rights to all congestion revenues are assigned to load. The product sold to FTR buyers is incorrectly defined as target allocations rather than a share of congestion revenue. ARR holders' rights to congestion revenues are not correctly defined because the contract path based assignment of congestion rights is inadequate and incorrect. Ongoing PJM subjective intervention in the FTR market that affects market fundamentals is also an issue and a symptom of the fundamental flaws in the design. The product, the quantity of the product and the price of the product are all incorrectly defined.
- The fact that load is not able to define its willingness to sell FTRs or the prices at which it is willing to sell FTRs and the fact that sellers are required to return some of the cleared auction revenue to FTR buyers when FTR profits are not adequate, means that the FTR design does not actually function as a market and is evidence of basic flaws in the market design.

Role of MMU

FERC assigns three core functions to MMUs: reporting, monitoring and market design.[17] These functions are interrelated and overlap. The PJM Market Monitoring Plan establishes these functions, providing that the MMU is responsible for monitoring: compliance with the PJM Market Rules; actual or potential design flaws in the PJM Market Rules; structural problems in the PJM Markets that may inhibit a robust and competitive market; the actual or potential exercise of market power or violation of the market rules by a Market Participant; PJM's implementation of the PJM Market Rules or operation of the PJM Markets; and such matters as are necessary to prepare reports.[18]

Reporting

The MMU performs its reporting function primarily by issuing and filing annual and quarterly state of the market reports; regular reports on market issues, such as RPM auction reports; reports responding to requests from regulators and other authorities; and ad hoc reports on specific topics. The state of the market reports provide a comprehensive analysis of market structure, participant conduct and market performance for the PJM markets. State of the market reports and other reports are intended to inform PJM, the PJM Board, FERC, other regulators, other authorities, market participants, stakeholders and the general public about how well PJM markets achieve the competitive outcomes necessary to realize the goals of regulation through competition, and how the markets can be improved.

The MMU presents reports directly to PJM stakeholders, PJM staff, FERC staff, state commission staff, state commissions, other regulatory agencies and the general public. Report presentations provide an opportunity for interested parties to ask questions, discuss issues, and provide feedback to the MMU.

Monitoring

To perform its monitoring function, the MMU screens and monitors the conduct of Market Participants under the MMU's broad purview to monitor, investigate, evaluate and report on the PJM Markets.[19] The MMU has direct, confidential access to FERC.[20] The MMU may also refer matters to the attention of state commissions.[21]

The MMU monitors market behavior for violations of FERC Market Rules and PJM Market Rules, including the actual or potential exercise of market power.[22] The MMU will investigate and refer "Market Violations," which refer to any of "a tariff violation, violation of a Commission-approved order, rule or regulation, market manipulation, or inappropriate dispatch that creates substantial concerns regarding unnecessary market inefficiencies…"[23] [24] [25] The MMU also monitors PJM for compliance with the rules, in addition to market participants.[26]

An important component of the monitoring function is the review of inputs to mitigation. The actual or potential exercise of market power is addressed in part through *ex ante* mitigation rules incorporated in PJM's market clearing software for the energy market, the capacity market and the regulation market. If a market participant fails the TPS test in any of these markets its offer is set to the lower of its price-based or cost-based offer. This prevents the exercise of market power and ensures competitive pricing, provided that the cost-based offer accurately reflects short run marginal cost.

17 18 CFR § 35.28(g)(3)(ii); see also *Wholesale Competition in Regions with Organized Electric Markets*, Order No. 719, FERC Stats. & Regs. ¶31,281 (2008) ("Order No. 719"), *order on reh'g*, Order No. 719-A, FERC Stats. & Regs. ¶31,292 (2009), *reh'g denied*, Order No. 719-B, 129 FERC ¶ 61,252 (2009).
18 OATT Attachment M § IV; 18 CFR § 1c.2.
19 OATT Attachment M § IV.
20 OATT Attachment M § IV.K.3.
21 OATT Attachment M § IV.H.
22 OATT § I.1 ("FERC Market Rules" mean the market behavior rules and the prohibition against electric energy market manipulation codified by the Commission in its Rules and Regulations at 18 CFR §§ 1c.2 and 35.37, respectively; the Commission-approved PJM Market Rules and any related proscriptions or any successor rules that the Commission from time to time may issue, approve or otherwise establish… "PJM Market Rules" mean the rules, standards, procedures, and practices of the PJM Markets set forth in the PJM Tariff, the PJM Operating Agreement, the PJM Reliability Assurance Agreement, the PJM Consolidated Transmission Owners Agreement, the PJM Manuals, the PJM Regional Practices Document, the PJM-Midwest Independent Transmission System Operator Joint Operating Agreement or any other document setting forth market rules.")
23 FERC defines manipulation as engaging "in any act, practice, or course of business that operates or would operate as a fraud or deceit upon any entity." 18 CFR § 1c.2(a)(3). Manipulation may involve behavior that is consistent with the letter of the rules, but violates their spirit. An example is market behavior that is economically meaningless, such as equal and opposite transactions, which may entitle the transacting party to a benefit associated with volume. Unlike market power or rule violations, manipulation must be intentional. The MMU must build its case, including an inference of intent, on the basis of market data.
24 OATT § I.1.
25 The MMU has no prosecutorial or enforcement authority. The MMU notifies FERC when it identifies a significant market problem or market violation. OATT Attachment M § IV.I.1. If the problem or violation involves a market participant, the MMU discusses the matter with the participant(s) involved and analyzes relevant market data. If that investigation produces sufficient credible evidence of a violation, the MMU prepares a formal referral and thereafter undertakes additional investigation of the specific matter only at the direction of FERC staff. *Id.* If the problem involves an existing or proposed law, rule or practice that exposes PJM markets to the risk that market power or market manipulation could compromise the integrity of the markets, the MMU explains the issue, as appropriate, to FERC, state regulators, stakeholders or other authorities. The MMU may also initiate, participate as a party or provide information or testimony in regulatory or other proceedings.
26 OATT Attachment M § IV.C.

If cost-based offers do not accurately reflect short run marginal cost, the market power mitigation process does not ensure competitive pricing in PJM markets. The MMU evaluates the fuel cost policy for every unit as well as the other inputs to cost-based offers. PJM Manual 15 does not clearly or accurately describe the short run marginal cost of generation. Manual 15 should be replaced with a straightforward description of the components of cost offers based on short run marginal costs and the correct calculation of cost offers. The MMU evaluates every offer cap in each capacity market (RPM) auction using data submitted to the MMU through web-based data input systems developed by the MMU.[27]

The MMU also reviews operational parameter limits included with unit offers, evaluates compliance with the requirement to offer into the energy and capacity markets, evaluates the economic basis for unit retirement requests and evaluates and compares offers in the day-ahead and real-time energy markets.[28] [29] [30] [31]

The MMU reviews offers and inputs in order to evaluate whether those offers raise market power concerns. Market participants, not the MMU, determine and take responsibility for offers that they submit and the market conduct that those offers represent. If the MMU has a concern about an offer, the MMU may raise that concern with FERC or other regulatory authorities. FERC and other regulators have enforcement and regulatory authority that they may exercise with respect to offers submitted by market participants. PJM also reviews offers, but it does so in order to determine whether offers comply with the PJM tariff and manuals. PJM, in its role as the market operator, may reject an offer that fails to comply with the market rules. The respective reviews performed by the MMU and PJM are separate and non-sequential.

The PJM markets monitored by the MMU include market related procurement processes conducted by PJM, such as for Black Start resources included in the PJM system restoration plan.[32] [33]

27 OATT Attachment M–Appendix § II.E.
28 OATT Attachment M–Appendix § II.B.
29 OATT Attachment M–Appendix § II.C.
30 OATT Attachment M–Appendix § IV.
31 OATT Attachment M–Appendix § VII.
32 OATT Attachment M–Appendix § II(p).
33 OATT Attachment M–Appendix § III.

The MMU also monitors transmission planning, interconnections and rules for vertical market power issues, and with the introduction of competitive transmission development policy in Order No. 1000, horizontal market power issues.[34]

Market Design

In order to perform its role in PJM market design, the MMU evaluates existing and proposed PJM Market Rules and the design of the PJM Markets.[35] The MMU initiates and proposes changes to the design of such markets or the PJM Market Rules in stakeholder or regulatory proceedings.[36] In support of this function, the MMU engages in discussions with stakeholders, State Commissions, PJM Management, and the PJM Board; participates in PJM stakeholder meetings or working groups regarding market design matters; publishes proposals, reports or studies on such market design issues; and makes filings with the Commission on market design, market rules and market rule implementation issues, including complaints or petitions.[37] The MMU also recommends changes to the PJM Market Rules to the staff of the Commission's Office of Energy Market Regulation, State Commissions, and the PJM Board.[38] The MMU may provide in its annual, quarterly and other reports "recommendations regarding any matter within its purview."[39]

New Recommendations

Consistent with its core function to "[e]valuate existing and proposed market rules, tariff provisions and market design elements and recommend proposed rule and tariff changes," the MMU recommends specific enhancements to existing market rules and implementation of new rules that are required for competitive results in PJM markets and for continued improvements in the functioning of PJM markets.[40]

In this *2023 Quarterly State of the Market Report for PJM: January through March*, the MMU includes four new recommendations.

34 OA Schedule 6 § 1.5.
35 OATT Attachment M § IV.D.
36 *Id.*
37 *Id.*; see also, e.g., 171 FERC ¶ 61,039; 167 FERC ¶ 61,084 at PP 70–76, *reh'g denied*, 168 FERC ¶ 61,141.
38 *Id.*
39 OATT Attachment M § VI.A.
40 18 CFR § 35.28(g)(3)(ii)(A); see also OATT Attachment M § IV.D.

New Recommendation from Section 6, Demand Response

- The MMU recommends that PJM report the response of demand capacity resources to dispatch by PJM as the actual change in load rather than simply the difference between the amount of capacity purchased by the customer and the actual metered load. The current approach significantly overstates the response to PJM dispatch. (Priority: High. New recommendation. Status: Not adopted.)

New Recommendations from Section 10, Ancillary Services

- The MMU recommends that the two signal regulation market design be replaced with a one signal regulation market design. (Priority: Medium. New recommendation. Status: Not adopted.)
- The MMU recommends that black start planning and coordination be on a regional basis and not on a zonal basis and that the costs of black start service be shared equally across the region. (Priority: Medium. New recommendation. Status: Not adopted.)

New Recommendation from Section 12, Generation and Transmission Planning

- Given the significance of data to market participants and regulators, the MMU recommends that all queue data and supplemental, network and baseline project data, including projected in service dates and estimated and final costs, be regularly updated with accurate and verifiable data. (Priority: High. New recommendation. Not adopted.)

Total Price of Wholesale Power

The total price of wholesale power is the total price per MWh of wholesale electricity in PJM markets.[41] The total price is an average price. Prices vary by location and time period. The total price includes the price of energy, capacity, transmission service, ancillary services, and administrative fees, regulatory support fees and uplift charges billed through PJM systems. Table 1-8 shows the average price, by component, for the first three months of 2022 and 2023.

The total costs for each year shown in Table 1-8 equal the total price per MWh, by category, multiplied by the total load. The total costs are different from the total billing values that PJM reports as shown in Figure 1-2. PJM's reported total billing values represent the total dollars that pass through the PJM settlement process.

Each of the components in Table 1-8 is defined in PJM's Open Access Transmission Tariff (OATT) and PJM Operating Agreement and each is collected through PJM's billing system.

Components of Total Price

- The Energy component is the real-time load weighted average PJM locational marginal price (LMP).
- The Capacity component is the average price per MWh of Reliability Pricing Model (RPM) payments.
- The Transmission Service Charges component is the average price per MWh of network integration charges, and firm and nonfirm point to point transmission service.[42]
- The Energy Uplift (Operating Reserves) component is the average price per MWh of day-ahead and balancing operating reserves and synchronous condensing charges.[43]

41 Accounting load is used in the calculation of total price because accounting load is the load customers pay for in PJM settlements. The use of accounting load with losses before June 1, 2007 and without losses after June 1, 2007, is consistent with PJM's calculation of LMP. Before June 1, 2007, transmission losses were included in accounting load. After June 1, 2007, transmission losses were excluded from accounting load and losses were addressed through the incorporation of marginal loss pricing in LMP.
42 OATT §§ 13.7, 14.5, 27A & 34.
43 OA Schedules 1 §§ 3.2.3 & 3.3.3.

- The Reactive component is the average cost per MWh of reactive supply and voltage control from generation and other sources.[44]
- The Regulation component is the average cost per MWh of regulation procured through the PJM Regulation Market.[45]
- The PJM Administrative Fees component is the average cost per MWh of PJM's monthly expenses for a number of administrative services, including Advanced Control Center (AC^2) and OATT Schedule 9 funding of FERC, OPSI, CAPS and the MMU.
- The Transmission Enhancement Cost Recovery component is the average cost per MWh of PJM billed (and not otherwise collected through utility rates) costs for transmission upgrades and projects, including annual recovery for the TrAIL and PATH projects.[46]
- The Capacity (FRR) component is the average cost per MWh under the Fixed Resource Requirement (FRR) Alternative for an eligible LSE to satisfy its Unforced Capacity obligation.[47]
- The Emergency Load Response component is the average cost per MWh of the PJM Emergency Load Response Program.[48]
- The Day-Ahead Scheduling Reserve component is the average cost per MWh of Day-Ahead scheduling reserves procured through the day-ahead scheduling reserve market.[49]
- The Transmission Owner (Schedule 1A) component is the average cost per MWh of transmission owner scheduling, system control and dispatch services charged to transmission customers.[50]
- The Synchronized Reserve component is the average cost per MWh of synchronized reserve procured through the Synchronized Reserve Market.[51]
- The Black Start component is the average cost per MWh of black start service.[52]
- The RTO Startup and Expansion component is the average cost per MWh of charges to recover AEP, COMED and DAY's integration expenses.[53]
- The NERC/RFC component is the average cost per MWh of NERC and RFC charges, plus any reconciliation charges.[54]
- The Economic Load Response component is the average cost per MWh of day-ahead and real-time economic load response program charges to LSEs.[55]
- The Transmission Facility Charges component is the average cost per MWh of Ramapo Phase Angle Regulators charges allocated to PJM Mid-Atlantic transmission owners.[56]
- The Nonsynchronized Reserve component is the average cost per MWh of non-synchronized reserve procured through the Non-Synchronized Reserve Market.[57]
- The Emergency Energy component is the average cost per MWh of emergency energy.[58]

44 OATT Schedule 2 and OA Schedule 1 § 3.2.3B. The line item in Table 08 includes all reactive services charges.
45 OA Schedules 1 §§ 3.2.2, 3.2.2A, 3.3.2, & 3.3.2A; OATT Schedule 3.
46 OATT Schedule 12.
47 RAA Schedule 8.1.
48 OATT PJM Emergency Load Response Program.
49 OA Schedules 1 §§ 3.2.3A.01 & OATT Schedule 6.
50 OATT Schedule 1A.
51 OA Schedule 1 § 3.2.3A.01; PJM OATT Schedule 6.
52 OATT Schedule 6A. The line item in Table 1-8includes all Energy Uplift (Operating Reserves) charges for Black Start.
53 OATT Attachments H-13, H-14 and H-15 and Schedule 13.
54 OATT Schedule 10-NERC and OATT Schedule 10-RFC.
55 OA Schedule 1 § 3.6.
56 OA Schedule 1 § 5.3b.
57 OA Schedule 1 § 3.2.3A.001.
58 OA Schedule 1 § 3.2.6.

Table 1-8 shows that energy, capacity and transmission charges are the three largest components of the total price per MWh of wholesale power, comprising 96.6 percent of the total price per MWh in the first three months of 2023. The total price per MWh of wholesale power decreased from $81.84 in the first three months of 2022 to $53.45 in the first three months of 2023, a decrease of 34.7 percent. Starting in the third quarter of 2019, the cost of transmission per MWh of wholesale power has been higher than the cost of capacity.

Table 1-8 Total price per MWh by category: January through March, 2022 and 2023[59 60 61 62]

Category	2022 (Jan-Mar) $/MWh	2022 (Jan-Mar) ($ Millions)	2022 (Jan-Mar) Percent of Total	2023 (Jan-Mar) $/MWh	2023 (Jan-Mar) ($ Millions)	2023 (Jan-Mar) Percent of Total	Percent Change
Load Weighted Energy	$54.13	$10,752	66.1%	$30.28	$5,707	56.6%	(44.1%)
Capacity	$11.66	$2,316	14.2%	$5.24	$988	9.8%	(55.0%)
Capacity	$11.65	$2,315	14.2%	$5.17	$974	9.7%	(55.6%)
Capacity (FRR)	$0.00	$1	0.0%	$0.01	$1	0.0%	6.1%
Capacity (RMR)	$0.00	$0	0.0%	$0.07	$13	0.1%	0.0%
Transmission	$14.45	$2,870	17.7%	$16.13	$3,041	30.2%	11.6%
Transmission Service Charges	$12.15	$2,413	14.8%	$13.73	$2,588	25.7%	13.0%
Transmission Enhancement Cost Recovery	$2.22	$441	2.7%	$2.32	$437	4.3%	4.3%
Transmission Owner (Schedule 1A)	$0.08	$15	0.1%	$0.08	$15	0.2%	5.9%
Transmission Seams Elimination Cost Assignment (SECA)	$0.00	$0	0.0%	$0.00	$0	0.0%	0.0%
Transmission Facility Charges	$0.00	$0	0.0%	$0.00	$0	0.0%	0.0%
Ancillary	$1.00	$198	1.2%	$0.76	$144	1.4%	(23.4%)
Reactive	$0.48	$96	0.6%	$0.51	$96	1.0%	5.9%
Regulation	$0.31	$61	0.4%	$0.15	$27	0.3%	(52.9%)
Black Start	$0.09	$18	0.1%	$0.09	$17	0.2%	(0.3%)
Synchronized Reserves	$0.07	$15	0.1%	$0.02	$4	0.0%	(72.4%)
Secondary Reserves	$0.00	$0	0.0%	$0.00	$0	0.0%	0.0%
Non-Synchronized Reserves	$0.04	$9	0.1%	($0.00)	($0)	(0.0%)	(100.7%)
Day Ahead Scheduling Reserve (DASR)	$0.00	$0	0.0%	$0.00	$0	0.0%	(100.0%)
Administration	$0.46	$92	0.6%	$0.59	$111	1.1%	28.0%
PJM Administrative Fees	$0.43	$85	0.5%	$0.55	$104	1.0%	29.8%
NERC/RFC	$0.04	$7	0.0%	$0.04	$7	0.1%	7.8%
RTO Startup and Expansion	$0.00	$0	0.0%	$0.00	$0	0.0%	0.0%
Energy Uplift (Operating Reserves)	$0.14	$28	0.2%	$0.10	$19	0.2%	(26.2%)
Demand Response	$0.00	$0	0.0%	$0.34	$64	0.6%	17,736.8%
Load Response	$0.00	$0	0.0%	$0.02	$3	0.0%	731.6%
Emergency Load Response	$0.00	$0	0.0%	$0.32	$61	0.6%	0.0%
Emergency Energy	$0.00	$0	0.0%	$0.00	$0	0.0%	0.0%
Other	$0.00	$1	0.0%	$0.01	$1	0.0%	23.3%
Total Price	$81.84	$16,257	100.0%	$53.45	$10,076	100.0%	(34.7%)
Total Load (GWh)	198,644			188,505			(5.1%)
Total Cost ($ Billions)	$16.26			$10.08			(38.0%)

59 The totals in the Transmission section of this table include corrections to previously reported totals which did not include a full accounting of Transmission Enhancement Cost Recovery costs. The MMU is currently reevaluating the total cost of wholesale power calculation.
60 Note: The totals in this table include after the fact billing adjustments and may not match totals presented in past reports.
61 The total cost in this table does not match the PJM reported total billing due to differences in calculation methods. The total prices in this table are load weighted average system prices per MWh by category, even if each category is not charged on a per MWh basis. PJM's reported total billing represents the total dollars that pass through the PJM settlement process.
62 The MMU publishes monthly detail of these components of PJM price. See <http://www.monitoringanalytics.com/data/pjm_price.shtml>.

Table 1-9 shows the inflation adjusted average price, by component, for the first three months of 2022 and 2023. To calculate the inflation adjusted average prices, the individual components' prices are deflated using the US Consumer Price Index for all items, Urban Consumers (with a base period of January 1998).[63]

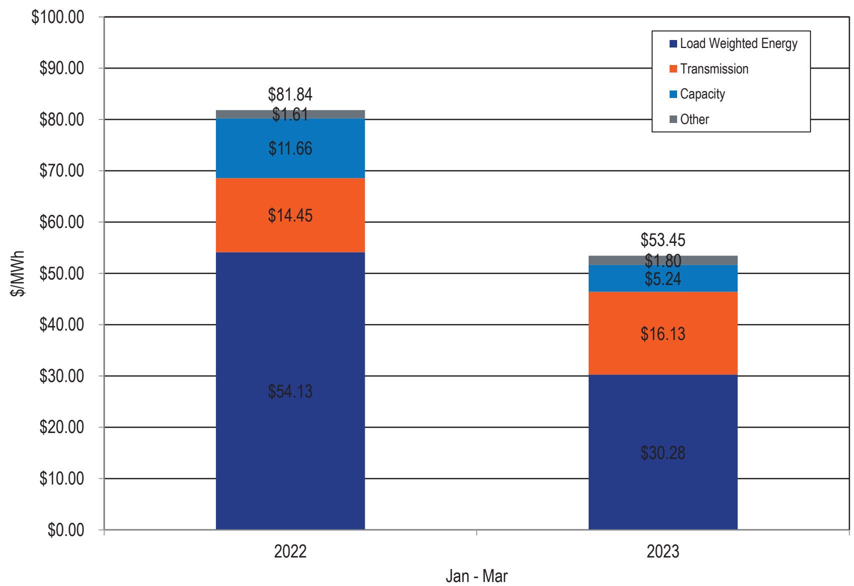
Table 1-9 Inflation adjusted total price per MWh by category: January through March, 2022 and 2023[64 65]

Category	2022 (Jan-Mar) $/MWh	2022 (Jan-Mar) ($ Millions)	2022 (Jan-Mar) Percent of Total	2023 (Jan-Mar) $/MWh	2023 (Jan-Mar) ($ Millions)	2023 (Jan-Mar) Percent of Total	Percent Change
Load Weighted Energy	$30.86	$6,131	65.7%	$16.29	$3,070	56.4%	(47.2%)
Capacity	$7.00	$1,391	14.9%	$2.94	$553	10.2%	(58.1%)
Capacity	$7.00	$1,390	14.9%	$2.90	$546	10.0%	(58.6%)
Capacity (FRR)	$0.00	$1	0.0%	$0.00	$1	0.0%	0.0%
Capacity (RMR)	$0.00	$0	0.0%	$0.04	$7	0.1%	0.0%
Transmission	$8.22	$1,632	17.5%	$8.67	$1,635	30.0%	5.5%
Transmission Service Charges	$6.91	$1,373	14.7%	$7.38	$1,391	25.6%	6.8%
Transmission Enhancement Cost Recovery	$1.26	$251	2.7%	$1.25	$235	4.3%	(1.4%)
Transmission Owner (Schedule 1A)	$0.04	$9	0.1%	$0.04	$8	0.2%	0.0%
Transmission Seams Elimination Cost Assignment (SECA)	$0.00	$0	0.0%	$0.00	$0	0.0%	0.0%
Transmission Facility Charges	$0.00	$0	0.0%	$0.00	$0	0.0%	0.0%
Ancillary	$0.57	$113	1.2%	$0.41	$77	1.4%	(27.7%)
Reactive	$0.27	$54	0.6%	$0.27	$52	1.0%	0.1%
Regulation	$0.18	$35	0.4%	$0.08	$15	0.3%	(55.6%)
Black Start	$0.05	$10	0.1%	$0.05	$9	0.2%	(5.8%)
Synchronized Reserves	$0.04	$8	0.1%	$0.01	$2	0.0%	(73.9%)
Non-Synchronized Reserves	$0.03	$5	0.1%	($0.00)	($0)	(0.0%)	(100.4%)
Day Ahead Scheduling Reserve (DASR)	$0.00	$0	0.0%	$0.00	$0	0.0%	(100.0%)
Administration	$0.26	$52	0.6%	$0.32	$60	1.1%	21.0%
PJM Administrative Fees	$0.24	$48	0.5%	$0.30	$56	1.0%	22.7%
NERC/RFC	$0.02	$4	0.0%	$0.02	$4	0.1%	2.0%
RTO Startup and Expansion	$0.00	$0	0.0%	$0.00	$0	0.0%	0.0%
Energy Uplift (Operating Reserves)	$0.08	$16	0.2%	$0.06	$10	0.2%	(30.5%)
Demand Response	$0.00	$0	0.0%	$0.18	$34	0.6%	18,060.0%
Load Response	$0.00	$0	0.0%	$0.01	$2	0.0%	760.0%
Emergency Load Response	$0.00	$0	0.0%	$0.17	$33	0.6%	0.0%
Emergency Energy	$0.00	$0	0.0%	$0.00	$0	0.0%	0.0%
Other	$0.00	$0	0.0%	$0.00	$1	0.0%	16.7%
Total Price	$47.00	$9,336	100.0%	$28.86	$5,440	100.0%	(38.6%)
Total Load (GWh)	198,644			188,505			(5.1%)
Total Cost ($ Billions)	$9.34			$5.44			(41.7%)

63 US Consumer Price Index for all items, Urban Consumers (base period: January 1998), published by *Bureau of Labor Statistics*. <http://download.bls.gov/pub/time.series/cu/cu.data.1.AllItems> (April 12, 2023).
64 The totals in the Transmission section of this table include corrections to previously reported totals which did not include a full accounting of Transmission Enhancement Cost Recovery costs. The MMU is currently reevaluating the total cost of wholesale power calculation.
65 Note: The totals in this table include after the fact billing adjustments and may not match totals presented in past reports.

Figure 1-3 shows the total price of wholesale power in the first three months of 2022 and 2023.

Figure 1-3 Total price per MWh by category: January through March, 2022 and 2023



Section Overviews

Overview: Section 3, Energy Market

Supply and Demand

Market Structure

- **Supply.** In the first three months of 2023, 146 MW of new resources were added in the energy market, and 0 MW of resources were retired.
- The real-time hourly on peak average offered supply was 148,236 MW in the winter of 2021/2022, and 141,798 MW in the winter of 2022/2023. The day-ahead hourly on peak average offered supply was 168,965 MW in the winter of 2021/2022, and 163,028 MW in the winter of 2022/2023.
- The real-time hourly average cleared generation in the first three months of 2023 decreased by 5.7 percent from the first three months of 2022, from 98,506 MWh to 92,936 MWh.
- The day-ahead hourly average supply in the first three months of 2023, including INCs and UTCs, increased by 7.3 percent from the first three months of 2022, from 113,169 MWh to 121,433 MWh.
- **Demand.** The real-time hourly peak load plus exports in the first three months of 2023 was 123,504 MWh (117,705 MWh of load plus 5,798 MWh of gross exports) in the HE 2000 (EPT) on February 03, 2023, which was 5.6 percent, 7,276 MWh, lower than the PJM peak load plus exports in the first three months of 2022, which was 130,779 MWh in the HE 0800 (EPT) on January 27, 2022.
- The real-time hourly average load in the first three months of 2023 decreased by 5.1 percent from the first three months of 2022, from 92,007 MWh to 87,311 MWh.
- The day-ahead hourly average demand in the first three months of 2023, including DECs and UTCs, increased by 8.2 percent from the first three months of 2022, from 106,845 MWh to 115,558 MWh.

Market Behavior

- **Virtual Offers and Bids.** Any market participant in the PJM Day-Ahead Energy Market can use increment offers, decrement bids, up to congestion transactions, import transactions and export transactions as financial instruments that do not require physical generation or load. The hourly average submitted increment offer MW increased by 5.6 percent and cleared increment MW increased by 25.2 percent in the first three months of 2023 compared to the first three months of 2022. The hourly average submitted decrement bid MW decreased by 23.3 percent and cleared decrement MW decreased by 25.1 percent in the first three months of 2023 compared to the first three months of 2022. The hourly average submitted up to congestion bid MW increased by 186.1 percent and cleared up to congestion bid MW increased by 135.2 percent in the first three months of 2023 compared to the first three months of 2022.

Market Performance[66]

- **Generation Fuel Mix.** In the first three months of 2023, generation from coal units decreased 40.1 percent, generation from natural gas units increased 12.5 percent, and generation from oil decreased 11.9 percent compared to the first three months of 2022. Wind and solar output rose by 3.6 percent compared to the first three months of 2022, supplying 5.8 percent of PJM energy in the first three months of 2023.
- **Fuel Diversity.** The fuel diversity of energy generation in the first three month of 2023, measured by the fuel diversity index for energy (FDI_e), decreased 4.1 percent compared to the first three months of 2022.
- **Marginal Resources.** In the PJM Real-Time Energy Market in the first three months of 2023, coal units were 11.6 percent and natural gas units were 79.0 percent of marginal resources. In the first three months of 2022, coal units were 15.3 percent and natural gas units were 63.6 percent of marginal resources.

  In the PJM Day-Ahead Energy Market in the first three months of 2023, UTCs were 57.3 percent, INCs were 13.3 percent, DECs were 16.9 percent, and generation resources were 12.1 percent of marginal resources. In the first three months of 2022, UTCs were 37.4 percent, INCs were 20.1 percent, DECs were 24.9 percent, and generation resources were 17.5 percent of marginal resources.
- **Prices.** The real-time load-weighted average LMP in the first three months of 2023 decreased 44.1 percent from the first three months of 2022, from $54.13 per MWh to $30.28 per MWh.

  The day-ahead load-weighted average LMP in the first three months of 2023 decreased 40.7 percent from the first three months of 2022, from $54.23 per MWh to $32.16 per MWh.
- **Fast Start Pricing.** The real-time load-weighted average PLMP was $30.28 per MWh for the first three months of 2023, which is 2.9 percent, $0.85 per MWh, higher than the real-time load-weighted average DLMP of $29.43 per MWh.
- **Components of LMP.** In the PJM Real-Time Energy Market in the first three months of 2023, 18.2 percent of the load-weighted LMP was the result of coal costs, 53.7 percent was the result of gas costs, 5.3 percent was the result of the cost of emission allowances, 2.5 percent was the result of transmission constraint violation penalty factors, and, 1.6 percent was the result of the commitment costs of fast start units.

  Of the $23.85 per MWh decrease in the real-time load weighted average LMP, $13.89 per MWh (58.2 percent) was in the fuel and consumables cost components of LMP, $0.26 per MWh (1.1 percent) was in the emissions cost components of LMP, $3.88 per MWh (14.0 percent) was in the sum of the markup, maintenance, and ten percent adder components of LMP, $3.65 per MWh (15.3 percent) was in the transmission constraint penalty factor component of LMP, and $0.50 per MWh (2.1 percent) was in the scarcity component of LMP.

  In the PJM Day-Ahead Energy Market in the first three months of 2023, 23.4 percent of the load-weighted LMP was the result of gas costs, 20.5 percent was the result of coal costs, 16.9 percent was the result of DEC bids, 21.9 percent was the result of INC offers, 7.9 percent was the result of positive markup, and 3.0 percent was the result of UTCs.

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

Of the $21.83 per MWh decrease in the day-ahead load weighted average LMP, $11.50 per MWh (52.7 percent) was in the virtual and dispatchable transactions cost components of LMP, $6.54 per MWh (29.9 percent) was in the fuel and consumables cost components of LMP, $0.46 per MWh (2.1 percent) was in the emissions cost components of LMP, $3.37 per MWh (15.4 percent) was in the sum of the markup, maintenance, and ten percent adder components of LMP.

- **Price Convergence.** Hourly and daily price differences between the day-ahead and real-time energy markets fluctuate continuously and substantially from positive to negative. The difference between day-ahead and real-time average prices was -$1.68 per MWh in the first three months of 2023, and -$0.30 per MWh in the first three months of 2022. The difference between day-ahead and real-time average prices, by itself, is not a measure of the competitiveness or effectiveness of the day-ahead energy market.

Scarcity

- There were three intervals with five minute shortage pricing on one day in the first three months of 2023. These shortages did not correspond with any emergency warning or action.
- There were 351 five minute intervals, or 1.4 percent of all five minute intervals, in the first three months of 2023 for which at least one RT SCED solution showed a shortage of reserves, and 101 five minute intervals, or 0.4 percent of all five minute intervals, in the first three months of 2023 for which more than one RT SCED solution showed a shortage of reserves. PJM triggered shortage pricing for three five minute intervals, or 0.01 percent of all five minute intervals.

Competitive Assessment

Market Structure

- **Aggregate Pivotal Suppliers.** The PJM energy market, at times, requires generation from pivotal suppliers to meet load, resulting in aggregate market power even when the HHI level indicates that the aggregate market is unconcentrated. Three suppliers were jointly pivotal in the day-ahead market on 16 days, 17.8 percent of days, in the first three months of 2023 and 66 days, 73.3 percent of days, in the first three months of 2022.
- **Local Market Power.** In the first three months of 2023, in the real-time market, nine zones experienced congestion resulting from one or more constraints binding for 25 or more hours. For seven out of the top 10 congested facilities (by real-time binding hours) in the first three months of 2023, the average number of suppliers providing constraint relief was three or fewer. There was a high level of concentration within the local markets for providing relief to the most congested facilities in the PJM Real-Time Energy Market. The local market structure was not competitive.

Market Behavior

- **Offer Capping for Local Market Power.** PJM offer caps units when the local market structure is noncompetitive. Offer capping is an effective means of addressing local market power when the rules are designed and implemented properly. Offer capping levels have historically been low in PJM. In the day-ahead energy market, for units committed to provide energy for local constraint relief, offer-capped unit hours decreased from 1.4 percent in the first three months of 2022 to 1.1 percent in the first three months of 2023. In the real-time energy market, for units committed to provide energy for local constraint relief, offer-capped unit hours decreased from 1.1 percent in the first three months of 2022 to 0.7 percent in the first three months of 2023. While overall offer capping levels have been low, there are a significant number of units with persistent structural local market power that would have had a significant impact on prices in the absence of local market power mitigation.

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

- **Offer Capping for Reliability.** PJM also offer caps units that are committed for reliability reasons, including for reactive support. In the day-ahead energy market, for units committed for reliability reasons, offer-capped unit hours increased from 0.00 percent in the first three months of 2022 to 0.06 percent in the first three months of 2023. In the real-time energy market, for units committed for reliability reasons, offer-capped unit hours increased from 0.00 percent in the first three months of 2022 to 0.03 percent in the first three months of 2023. The low offer cap percentages do not mean that units manually committed for reliability reasons do not have market power. All units manually committed for reliability have market power and all are treated as if they had market power. These units are not capped to their cost-based offers because they tend to offer with a negative markup in their price-based offers, particularly at the economic minimum level, which means that PJM's offer capping process results in the use of the price-based offer for commitment even if it has less flexible operating parameters.
- **Parameter Mitigation.** In the first three months of 2023, 34.6 percent of unit hours for units that failed the TPS test in the day-ahead market were committed on price-based schedules that were less flexible than their cost-based schedules. On days when cold weather alerts and hot weather alerts were declared, 27.0 percent of unit hours in the day-ahead energy market were committed on price-based schedules that were less flexible than their price PLS schedules.
- **Frequently Mitigated Units (FMU) and Associated Units (AU).** In the first three months of 2023, no units qualified for an FMU adder. In 2022, no units qualified for an FMU adder. In 2021, one unit qualified for an FMU adder.
- **Markup Index.** The markup index is a summary measure of participant offer behavior for individual marginal units. While the average markup index in the real-time market was -0.02 in the first three months of 2023, some marginal units did have substantial markups. The highest markup for any marginal unit in the real-time market in the first three months of 2023 was more than $200 per MWh when using unadjusted cost-based offers.

  While the average markup index in the day-ahead market was 0.14 in the first three months of 2023, some marginal units did have substantial markups. The highest markup for any marginal unit in the day-ahead market in the first three months of 2023 was more than $100 per MWh when using unadjusted cost-based offers.
- **Markup.** The markup frequency distributions show that a significant proportion of units make price-based offers less than the cost-based offers permitted under the PJM market rules. This behavior means that competitive price-based offers reveal actual unit marginal costs and that PJM market rules permit the inclusion of costs in cost-based offers that are not short run marginal costs.

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

Market Performance

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

  In the PJM Real-Time Energy Market in the first three months of 2023, the unadjusted markup component of LMP was $0.07 per MWh or 0.2 percent of the PJM load-weighted average LMP. March had the highest unadjusted peak markup component, $0.66 per MWh, or 2.2 percent of the real-time peak hour load-weighted average LMP for March.

  In the PJM Day-Ahead Energy Market, INCs, DECs and UTCs have zero markups. In the first three months of 2023, the unadjusted markup component of LMP was $0.44 per MWh or 1.4 percent of the PJM day-ahead load-weighted average LMP. January had the highest unadjusted peak markup component, $1.09 per MWh, or 3.6 percent of the day-ahead peak hour load-weighted average LMP for January.[67]

  Participant behavior was evaluated as competitive because the analysis of markup shows that marginal units generally make offers at, or close

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

to, their marginal costs in both the day-ahead and real-time energy markets, although the behavior of some participants represents economic withholding.

- **Markup and Local Market Power.** Comparison of the markup behavior of marginal units with TPS test results shows that for 3.6 percent of all real-time marginal unit intervals in the first three months of 2023, the marginal unit had both local market power as determined by the TPS test and a positive markup. The fact that units with market power had a positive markup means that the cost-based offer was not used, that a higher price-based offer was used, and that the process for offer capping units that fail the TPS test does not consistently result in competitive market outcomes in the presence of market power.
- **Markup and Aggregate Market Power.** In the first three months of 2023, pivotal suppliers in the aggregate market, committed in the day-ahead market and identified as one of three day-ahead aggregate pivotal suppliers, set real-time market prices with markups over $50 per MWh on nine days.

Section 3 Recommendations

Market Power

- The MMU recommends that the market rules explicitly require that offers in the energy market be competitive, where competitive is defined to be the short run marginal cost of the units. The short run marginal cost should reflect opportunity cost when appropriate. The MMU recommends that the level of incremental costs includable in cost-based offers not exceed the short run marginal cost of the unit. (Priority: Medium. First reported 2009. Status: Not adopted.)

Fuel Cost Policies

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

Cost-Based Offers

- The MMU recommends that Manual 15 (Cost Development Guidelines) be replaced or updated with a straightforward description of the components of cost-based offers and the mathematically correct calculation of cost-based offers. (Priority: Medium. First reported 2016. Status: Partially adopted Q1 2022.)[68]
- The MMU recommends removal of all use of FERC System of Accounts in the Cost Development Guidelines. (Priority: Medium. First reported 2016. Status: Not adopted.)
- The MMU recommends the removal of all use of cyclic starting and peaking factors from the Cost Development Guidelines. (Priority: Medium. First reported 2016. Status: Not adopted.)
- The MMU recommends the removal of all labor costs from the Cost Development Guidelines. (Priority: Medium. First reported 2016. Status: Adopted 2022.)
- The MMU recommends the removal of all maintenance costs from the Cost Development Guidelines. (Priority: Medium. First reported 2019. Status: Not adopted.)
- The MMU recommends that market participants be required to document the amount and cost of consumables used when operating in order to verify that the total operating cost is consistent with the total quantity used and the unit characteristics. (Priority: Medium. First reported 2020. Status: Adopted 2023.)

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

- The MMU recommends, given that maintenance costs are currently allowed in cost-based offers, that market participants be permitted to include only variable maintenance costs, linked to verifiable operational events and that can be supported by clear and unambiguous documentation of the operational data (e.g. run hours, MWh, MMBtu) that support the maintenance cycle of the equipment being serviced/replaced. (Priority: Medium. First reported 2020. Status: Not adopted.)
- The MMU recommends explicitly accounting for soak costs and changing the definition of the start heat input for combined cycles to include only the amount of fuel used from first fire to the first breaker close in the Cost Development Guidelines. (Priority: Medium. First reported 2016. Status: Partially Adopted.)
- The MMU recommends that soak costs, soak time and the MWh produced during soaking be modeled separately. This will ensure that the time required for units to reach a dispatchable level is known and used in the unit commitment process instead of only being communicated verbally between dispatchers and generators. Separating soak costs from start costs and modeling the MWh produced during soaking allows for a better representation of the costs because it eliminates the need to simply assume the price paid for those MWh. (Priority: Medium. First reported 2022. Status: Not Adopted.)
- The MMU recommends the removal of nuclear fuel and nonfuel operations and maintenance costs that are not short run marginal costs from the Cost Development Guidelines. (Priority: Medium. First reported 2016. Status: Not adopted.)
- The MMU recommends revising the pumped hydro fuel cost calculation to include day-ahead and real-time power purchases. (Priority: Low. First reported 2016. Status: Not adopted.)

Market Power: TPS Test and Offer Capping

- The MMU recommends that the rules governing the application of the TPS test be clarified and documented. The TPS test application in the day-ahead energy market is not documented. (Priority: High. First reported 2015. Status: Partially adopted.)[69]
- The MMU recommends that PJM modify the process of applying the TPS test in the day-ahead energy market to ensure that all local markets created by binding constraints are tested for market power and to ensure that market sellers with market power are appropriately mitigated to their competitive offers. (Priority: High. First reported Q1 2022. Status: Not adopted.)
- The MMU recommends, in order to ensure effective market power mitigation when the TPS test is failed, that offer capping be applied to units that fail the TPS test in the real-time market that were not offer capped at the time of commitment in the day-ahead market or at a prior time in the real-time market. (Priority: High. First reported 2020. Status: Not adopted.)
- The MMU recommends, in order to ensure effective market power mitigation and to ensure that capacity resources meet their obligations to be flexible, that capacity resources be required to use flexible parameters in all offers at all times. (Priority: High. First reported Q3 2021. Status: Not adopted.)
- The MMU recommends, if the preferred recommendation is not implemented, that in order to ensure effective market power mitigation, PJM always enforce parameter limited values when the TPS test is failed and during high load conditions such as cold and hot weather alerts and emergency conditions. (Priority: High. First reported 2015. Status: Not adopted.)
- The MMU recommends that PJM require every market participant to make available at least one cost schedule based on the same hourly fuel type(s) and parameters at least as flexible as their offered price schedule. (Priority: Medium. First reported 2015. Status: Not adopted.)

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

- The MMU recommends, in order to ensure effective market power mitigation when the TPS test is failed, that markup be consistently positive or negative across the full MWh range of price and cost-based offers. (Priority: High. First reported 2015. Status: Not adopted.)
- The MMU recommends that PJM retain the $1,000 per MWh offer cap in the PJM energy market except when cost-based offers exceed $1,000 per MWh, and retain other existing rules that limit incentives to exercise market power. (Priority: High. First reported 1999. Status: Partially adopted, 1999, 2017.)
- The MMU recommends the elimination of FMU and AU adders. FMU and AU adders no longer serve the purpose for which they were created and interfere with the efficient operation of PJM markets. (Priority: Medium. First reported 2012. Status: Partially adopted, 2014.)[70]

Offer Behavior

- The MMU recommends that resources not be allowed to violate the ICAP must offer requirement. The MMU recommends that PJM enforce the ICAP must offer requirement by assigning a forced outage to any unit that is derated in the energy market below its committed ICAP without an outage that reflects the derate. (Priority: Medium. First reported 2020. Status: Not adopted.)
- The MMU recommends that storage and intermittent resources be subject to an enforceable ICAP must offer rule that reflects the limitations of these resources. (Priority: Medium. First reported 2020. Status: Not adopted.)
- The MMU recommends that capacity resources not be allowed to offer any portion of their capacity market obligation as maximum emergency energy. (Priority: Medium. First reported 2012. Status: Not adopted.)
- The MMU recommends that PJM integrate all the outage reporting tools in order to enforce the ICAP must offer requirement, ensure that outages are reported correctly and eliminate reporting inconsistencies. Generators currently submit availability in three different tools that are not integrated, Markets Gateway, eDART and eGADS. (Priority: Medium. First reported 2022. Status: Not adopted.)
- The MMU recommends that gas generators be required to check with pipelines throughout the operating day to confirm that nominations are accepted beyond the NAESB deadlines, and that gas generators be required to place their units on forced outage until the time that pipelines allow nominations to consume gas at a unit. (Priority: Medium. First reported Q1 2022. Status: Not adopted.)

Capacity Resources

- The MMU recommends that capacity resources be held to the OEM operating parameters of the capacity market CONE reference resource for performance assessment and energy uplift payments and that this standard be applied to all technologies on a uniform basis. (Priority: Medium. First reported 2015. Status: Not adopted.)
- The MMU recommends that the parameters which determine nonperformance charges and the amounts of uplift payments should reflect the flexibility goals of the capacity market design. The operational parameters used by generation owners to indicate to PJM operators what a unit is capable of during the operating day should not determine capacity resource performance assessment or uplift payments. (Priority: Medium. First reported 2015. Status: Partially adopted.)[71]
- The MMU recommends that PJM clearly define the business rules that apply to the unit specific parameter adjustment process, including PJM's implementation of the tariff rules in the PJM manuals to ensure market sellers know the requirements for their resources. (Priority: Low. First reported 2018. Status: Not adopted.)
- The MMU recommends that PJM update the tariff to clarify that all generation resources are subject to unit specific parameter limits on their cost-based offers using the same standard and process as capacity resources. (Priority: Medium. First reported 2018. Status: Not adopted.)

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

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

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

Accurate System Modeling

- The MMU recommends that PJM explicitly state its policy on the use of transmission penalty factors including: the level of the penalty factors; the triggers for the use of the penalty factors; the appropriate line ratings to trigger the use of penalty factors; the allowed duration of the violation and when the transmission penalty factors will be used to set the shadow price. The MMU recommends that PJM end the practice of discretionary reductions in transmission line ratings modeled in the market clearing and included in LMP. (Priority: Medium. First reported 2015. Status: Partially adopted 2020.)[72]
- The MMU recommends that PJM routinely review all transmission facility ratings and any changes to those ratings to ensure that the normal, emergency and load dump ratings used in modeling the transmission system are accurate and reflect standard ratings practice. (Priority: Low. First reported 2013. Status: Not adopted.)
- The MMU recommends that PJM not use closed loop interface or surrogate constraints to artificially override nodal prices based on fundamental LMP logic in order to: accommodate rather than resolve the inadequacies of the demand side resource capacity product; address the inability of the power flow model to incorporate the need for reactive power; accommodate rather than resolve the flaws in PJM's approach to scarcity pricing; or for any other reason. (Priority: Medium. First reported 2013. Status: Not adopted.)
- The MMU recommends that PJM update the outage impact studies, the reliability analyses used in RPM for capacity deliverability, and the reliability analyses used in RTEP for transmission upgrades to be consistent with the more conservative emergency operations (post contingency load dump limit exceedance analysis) in the energy market that were implemented in June 2013.[73] (Priority: Low. First reported 2013. Status: Not adopted.)

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

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

- The MMU recommends that PJM include in the tariff or appropriate manual an explanation of the initial creation of hubs, the process for modifying hub definitions and a description of how hub definitions have changed.[74] [75] (Priority: Low. First reported 2013. Status: Not adopted.)
- The MMU recommends that all buses with a net withdrawal be treated as load for purposes of calculating load and load-weighted LMP, even if the MW are settled to the generator. The MMU recommends that during hours when a load bus shows a net injection, the energy injection be treated as generation, not negative load, for purposes of calculating generation and load-weighted LMP, even if the injection MW are settled to the load serving entity. (Priority: Low. First reported 2013. Status: Not adopted.)
- The MMU recommends that PJM identify and collect data on available behind the meter generation resources, including nodal location information and relevant operating parameters. (Priority: Low. First reported 2013. Status: Partially adopted.)
- The MMU recommends that PJM document how LMPs are calculated when demand response is marginal. (Priority: Low. First reported 2014. Status: Not adopted.)
- The MMU recommends that PJM not allow nuclear generators which do not respond to prices or which only respond to manual instructions from the operator to set the LMPs in the real-time market. (Priority: Low. First reported 2016. Status: Not adopted.)
- The MMU recommends that PJM increase the coordination of outage and operational restrictions data submitted by market participants via eDART/eGADs and offer data submitted via Markets Gateway. (Priority: Low. First reported 2017. Status: Not adopted.)
- The MMU recommends that PJM model generators' operating transitions, including soak time for units with a steam turbine, configuration transitions for combined cycles, and peak operating modes. (Priority: Medium. First reported 2019. Status: Not adopted.)

74 According to minutes from the first meeting of the Energy Market Committee (EMC) on January 28, 1998, the EMC unanimously agreed to be responsible for approving additions, deletions and changes to the hub definitions to be published and modeled by PJM. Since the EMC has become the Market Implementation Committee (MIC), the MIC now appears to be responsible for such changes.

75 There is currently no PJM documentation in the tariff or manuals explaining how hubs are created and how their definitions are changed. The general definition of a hub can be found in the PJM.com Glossary <http://www.pjm.com/Glossary.aspx>.

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

Transparency

- The MMU recommends that PJM clearly document the calculation of shortage prices and implementation of reserve price caps in the PJM manuals, including defining all the components of reserve prices, and all the constraints whose shadow prices are included in reserve prices. (Priority: High. First reported 2021. Status: Not adopted.)
- The MMU recommends that PJM allow generators to report fuel type on an hourly basis in their offer schedules and to designate schedule availability on an hourly basis. (Priority: Medium. First reported 2015. Status: Partially adopted.)[76]
- The MMU recommends that PJM define clear criteria for operator approval of RT SCED cases, including shortage cases, that are used to send dispatch signals to resources, and for pricing, to minimize discretion. (Priority: High. First reported 2018. Status: Partially adopted.)[77]

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

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

Virtual Bids and Offers

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

Section 3 Conclusion

The MMU analyzed key elements of PJM energy market structure, participant conduct and market performance in the first three months of 2023, including aggregate supply and demand, concentration ratios, aggregate pivotal supplier results, local three pivotal supplier test results, offer capping, markup, marginal units, participation in demand response programs, virtual bids and offers, loads and prices.

Prices are a key outcome of markets. Prices vary across hours, days and years for multiple reasons. Price is an indicator of the level of competition in a market. In a competitive market, prices are directly related to input prices, the marginal cost to serve load. In the first three months of 2023, LMP decreased by $23.85 per MWh compared to the first three months of 2022. The largest contributor to decreased prices was the cost of fuel, primarily natural gas and coal. The fuel cost components of LMP (the sum of gas, coal, oil, landfill gas, and consumables) decreased $13.89 per MWh, 58.2 percent of the decrease in LMP. The emissions cost components of LMP decreased by $0.26 per MWh, 1.1 percent of the decrease in LMP. The transmission constraint penalty factor component decreased by $1.64 per MWh, 6.9 percent of the decrease in LMP.

The pattern of prices within days and across months and years illustrates how prices are directly related to supply and demand conditions and illustrates the potential significance of the impact of the price elasticity of demand on prices. Energy market results in the first three months of 2023 generally reflected supply-demand fundamentals, although the behavior of some participants both routinely and during high demand periods represents economic withholding. Economic withholding occurs when generator offers are greater than competitive levels. In the first three months of 2023, economic withholding affected prices through marginal units using increased price markups and a ten percent cost adder applied to a higher fuel cost. The markup, ten percent adder, and maintenance cost components, together decreased by $3.35 per MWh or 14.0 percent of the decrease in LMP.

The potential for prolonged and excessively high administrative pricing in the energy market due to reserve penalty factors and transmission constraint penalty factors remains an issue that needs to be addressed.[78] There also continue to be significant issues with PJM's scarcity pricing rules, including the absence of a clear trigger based on accurately estimated reserve levels. For example, in July, August, and September of 2022, PJM approved a shortage case for one RT SCED five minute interval out of 673 intervals with multiple shortage solutions, while the same months in 2021 had only 404 intervals with multiple shortage solutions and nine approved shortage intervals. During Elliott, PJM approved 45.4 percent of SCED shortage solutions. The pattern of shortage case approvals indicates that PJM considers factors other than RT SCED producing a shortage case when deciding whether to approve shortage cases.

With or without a capacity market, energy market design must permit scarcity pricing when such pricing is consistent with market conditions and constrained by reasonable rules to ensure that market power is not exercised and ensure no scarcity pricing when such pricing is not consistent with market conditions. Scarcity pricing can serve two functions in wholesale power markets: revenue adequacy and price signals. Scarcity pricing for revenue adequacy, as in PJM's 2019 ORDC proposal, is not required in PJM. Scarcity pricing for price signals that reflect market conditions during periods of scarcity is required in PJM. Scarcity pricing is also part of an appropriate incentive structure facing both load and generation owners in a working wholesale electric power market design. Scarcity pricing must be designed to ensure that market prices reflect actual market conditions, that scarcity pricing occurs with transparent triggers based on measured reserve levels and transparent prices, that scarcity

78 177 FERC ¶ 61,209 (2021).

pricing only occurs when scarcity exists, that scarcity pricing not be excessive or punitive, and that there are strong incentives for competitive behavior and strong disincentives to exercise market power. Such administrative scarcity pricing is a key link between energy and capacity markets.

The PJM defined inputs to the dispatch tools, particularly the RT SCED, have substantial effects on energy market outcomes. Transmission line ratings, transmission penalty factors, load forecast bias, and hydro resource schedules change the dispatch of the system, affect prices, and can create significant price increases, particularly through transmission line limit violations. PJM operator interventions to reduce line ratings unnecessarily trigger transmission constraint penalty factors and significantly increase prices. Violations of the artificially reduced line limits had a direct effect on higher LMP in the first three months of 2023. If the line limits had not been artificially reduced for the PJM transmission constraints and everything else remained unchanged, fewer constraints would have been violated and the transmission penalty factor's contribution to the load weighted average LMP in the first three months of 2023 would have decreased by 99.1 percent from $0.75 to $0.01 per MWh. PJM should evaluate its interventions in the market, consider whether the interventions are appropriate, and provide greater transparency to enhance market efficiency.

Fast start pricing, implemented on September 1, 2021, has disconnected pricing from dispatch instructions and created a greater reliance on uplift rather than price as an incentive to follow PJM's instructions. The objective of efficient short run price signals is to minimize system production costs, not to minimize uplift. Repricing the market to reflect commitment costs using fast start pricing prioritizes minimizing uplift over minimizing production costs.[79] The tradeoff exists because when commitment costs are included in prices, the price signal no longer equals the short run marginal cost and therefore no longer provides the correct signal for efficient behavior for market participants making decisions on the margin, whether resources, load, interchange transactions, or virtual traders. Units that start in one hour are not actually fast start units, and their commitment costs are not marginal in a five minute market. The differences between the actual LMP and the fast start LMP will distort the incentive for market participants to behave competitively and to follow PJM's dispatch instructions. PJM is paying new forms of uplift in an attempt to counter the distorted incentives inherent in fast start pricing. PJM is also using the pricing run to implement other differences from the dispatch run that are not related to fast start pricing, including differences in transmission constraint penalty factors and system marginal price capping. Every difference between the dispatch run and the pricing run introduces another inefficiency in the market.

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

The relationship between supply and demand, regardless of the specific market, along with market concentration and the extent of pivotal suppliers, is referred to as the supply-demand fundamentals or economic fundamentals or market structure. The market structure of the PJM aggregate energy market is partially competitive because aggregate market power does exist for a significant number of hours. The HHI is not a definitive measure of structural market power. The number of pivotal suppliers in the energy market is a

79 See 173 FERC ¶ 61,244 (2020).

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

The three pivotal supplier test is applied by PJM on an ongoing basis for local energy markets in order to determine whether offer capping is required for transmission constraints.[80] However, there are some issues with the application of market power mitigation in the day-ahead energy market and the real-time energy market when market sellers fail the TPS test. The Commission recognized some of these issues in its order issued on June 17, 2021.[81] PJM continues to ignore the evidence cited by the Commission and denies the prevalence of these issues, instead of ensuring that market power mitigation works as intended and results in efficient market outcomes.[82] Many of these issues can be resolved by simple rule changes. The MMU proposed these rule changes in its response submitted on October 15, 2021, and continues to recommend them.[83] The MMU recommendations would shorten the solution time of the day-ahead market software, which would help facilitate enhanced combined cycle modelling. PJM proposes to weaken market power mitigation as part of implementing the enhanced combined cycle modelling project. PJM's proposals would ensure that the identified issues with the implementation of market power mitigation in the energy market would never be addressed and would be exacerbated.

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

A competitive market requires that prices increase when fuel costs increase and that prices decrease when fuel costs decrease. A competitive market does not require that prices increase when markup increases or when PJM artificially triggers transmission constraint penalty factors. The overall energy market results support the conclusion that energy prices in PJM are set, generally, by marginal units operating at, or close to, their marginal costs, although this was not always the case in the first three months of 2023 or prior years. Given the structure of the energy market which can permit the exercise of aggregate and local market power, the change in some participants' behavior is a source of concern in the energy market and provides a reason to use correctly defined short run marginal cost as the sole basis for cost-based offers and a reason for implementing an aggregate market power test and correcting the offer capping process for resources with local market power. The MMU concludes

80 The MMU reviews PJM's application of the TPS test and brings issues to the attention of PJM.
81 See 175 FERC ¶ 61,231 (2021).
82 *See* PJM. "Answer of PJM Interconnection L.L.C.," Docket No. EL21-78 (September 15, 2021).
83 *See* "Comments of the Independent Market Monitor for PJM," Docket No. EL21-78 (October 15, 2021).

that the PJM energy market results were competitive in the first three months of 2023.

Overview: Section 4, Energy Uplift

Energy Uplift Credits

- **Energy uplift credits.** Total energy uplift credits decreased by $8.6 million, or 30.5 percent, in the first three months of 2023 compared to the same time period in 2022, from $28.2 million to $19.6 million.
- **Types of energy uplift credits.** In the first three months of 2023, total energy uplift credits included $4.0 million in day-ahead generator credits, $11.7 million in balancing generator credits, $3.5 million in lost opportunity cost credits, and $0.1 million in local constraint control credits. Dispatch differential lost opportunity credits, which are a subset of balancing operating reserves, were implemented as part of fast start pricing on September 1, 2021, and were $0.1 million in the first three months of 2023. Regulation revenues should be included as an offset to uplift, but are not currently included.
- **Types of units.** In the first three months of 2023, coal units received 82.1 percent of day-ahead generator credits, and combustion turbines received 71.1 percent of balancing generator credits and 90.6 percent of lost opportunity cost credits. Combined cycle units and combustion turbines received 53.4 percent of dispatch differential lost opportunity credits.
- **Day-ahead unit commitment for reliability.** In the first three months of 2023, less than 1.0 percent of the total day-ahead generation MWh was scheduled as must run for reliability by PJM, of which 84.0 percent received energy uplift payments.
- **Concentration of energy uplift credits.** In the first three months of 2023, the top 10 units receiving energy uplift credits received 20.8 percent of all credits and the top 10 organizations received 42.3 percent of all credits. The HHI for day-ahead operating reserves was 8906, the HHI for balancing generator credits was 3055 and the HHI for lost opportunity cost was 5755, all of which are classified as highly concentrated.
- **Lost opportunity cost credits.** Lost opportunity cost credits decreased by $2.5 million, or 41.2 percent, in the first three months of 2023, compared to the same time period in 2022, from $6.6 million to $3.5 million.

  Some combustion turbines and diesels are scheduled day-ahead but not requested in real time, and receive day-ahead lost opportunity cost credits as a result. This was the source of 90.2 percent of the $3.5 million.
- **Following dispatch.** Some units are incorrectly paid uplift despite not meeting uplift eligibility requirements, including not following dispatch, not having the correct commitment status, or not operating with PLS offer parameters. Since 2018, the MMU has made cumulative resettlement requests for the most extreme overpaid units of $15.1 million, of which PJM has resettled only $1.4 million over the last two years, or 9.2 percent.
- **Daily uplift.** In the first three months of 2023, balancing generator charges would have been $1.9 million or 16.7 percent lower if they had been calculated on a daily basis rather than a segmented basis. Uplift was designed to be charged on a daily basis and not on an intraday segmented basis.
- **CT uplift exemption:** The rule that allowed CTs to be paid uplift regardless of how well they followed dispatch was terminated on November 1, 2022. Starting November 1, 2022, CTs are paid uplift if necessary to cover costs based on the lower of actual or desired output (as calculated by PJM based on the dispatch signal), like all other unit types.

Energy Uplift Charges

- **Energy Uplift Charges.** Total energy uplift charges (equal to total energy uplift credits) decreased by $8.6 million, or 30.5 percent, in the first three months of 2023 compared to the same time period in 2022, from $28.2 million to $19.6 million.
- **Types of Energy Uplift Charges.** In the first three months of 2023 total uplift charges included $4.0 million in day-ahead operating reserve charges, $15.4 million in balancing generator charges, and $0.1 million in black start services.

- **UTC Uplift.** Effective November 1, 2020, UTC transactions are allocated day-ahead and real-time uplift charges on a basis equivalent to a decrement bid (DEC) at the sink point of the UTC.[84]
- **Average Effective Operating Reserve Rates in the Eastern Region.** Day-ahead load, exports, DECs and UTCs paid $0.016 per MWh in the Eastern Region. Real-time load and exports paid an average of $0.048 per MWh. Deviations paid $0.089 per MWh in the Eastern Region.
- **Average Effective Operating Reserve Rates in the Western Region.** Day-ahead load, exports, DECs and UTCs paid $0.016 per MWh in the Western Region. Real-time load and exports paid $0.031 per MWh. Deviations paid $0.068 per MWh in the Western Region.

Geography of Charges and Credits

- In the first three months of 2023, 89.4 percent of all uplift charges allocated regionally (day-ahead operating reserves and balancing generator credits) were paid by MW at control zones, 3.3 percent by MW at hubs and aggregates, and 7.3 percent by MW at interchange interfaces.
- In the first three months of 2023, generators in the Eastern Region received 52.5 percent of all balancing generator credits, including lost opportunity cost and canceled resources credits.
- In the first three months of 2023, generators in the Western Region received 46.4 percent of all balancing generator credits, including lost opportunity cost and canceled resources credits.
- In the first three months of 2023, external pseudo tied generators received 1.1 percent of all balancing generator credits, including lost opportunity cost and canceled resources credits.

84 See 172 FERC ¶ 61,046 (2020).

Section 4 Recommendations

- The MMU recommends that uplift be paid only based on operating parameters that reflect the flexibility of the benchmark new entrant unit (CONE unit) in the PJM Capacity Market. (Priority: High. First reported 2018. Status: Not adopted.)
- The MMU recommends that PJM not pay uplift to units not following dispatch, including uplift related to fast start pricing, and require refunds where it has made such payments. This includes units whose offers are flagged for fixed generation in Markets Gateway because such units are not dispatchable. (Priority: Medium. First reported 2018. Status: Not adopted.)
- The MMU recommends that PJM pay uplift based on the offer at the lower of the actual unit output or the dispatch signal MW. (Priority: Medium. First reported 2018. Status: Not adopted.)
- The MMU recommends eliminating intraday segments from the calculation of uplift payments and returning to calculating the need for uplift based on the entire 24 hour operating day. (Priority: High. First reported 2018. Status: Not adopted.)
- The MMU recommends the elimination of day-ahead uplift to ensure that units receive an energy uplift payment based on their real-time output and not their day-ahead scheduled output. (Priority: Medium. First reported 2013. Status: Not adopted.)
- The MMU recommends that units not be paid lost opportunity cost uplift credits when PJM directs a unit to reduce output based on a transmission constraint or other reliability issue. There is no lost opportunity because the unit is required to reduce for the reliability of the unit and the system. (Priority: High. First reported 2021. Status: Not adopted.)
- The MMU recommends reincorporating the use of net regulation revenues as an offset in the calculation of balancing generator credits. (Priority: Medium. First reported 2009. Status: Not adopted.)
- The MMU recommends that self scheduled units not be paid energy uplift credits for their startup cost when the units are scheduled by PJM to start

before the self scheduled hours. (Priority: Low. First reported 2013. Status: Not adopted.)

- The MMU recommends three modifications to the energy lost opportunity cost calculations:
- The MMU recommends calculating LOC based on 24 hour daily periods for combustion turbines and diesels scheduled in the day-ahead energy market, but not committed in real time. (Priority: Medium. First reported 2014. Status: Not adopted.)
- The MMU recommends that units scheduled in the day-ahead energy market and not committed in real time should be compensated for LOC based on their real-time desired and achievable output, not their scheduled day-ahead output. (Priority: Medium. First reported 2015. Status: Not adopted.)
- The MMU recommends that only flexible fast start units (startup plus notification times of 10 minutes or less) and units with short minimum run times (one hour or less) be eligible by default for the LOC compensation to units scheduled in the day-ahead energy market and not committed in real time. Other units should be eligible for LOC compensation only if PJM explicitly cancels their day-ahead commitment. (Priority: Medium. First reported 2015. Status: Not adopted.)
- The MMU recommends that up to congestion (UTC) transactions be required to pay energy uplift charges for both the injection and the withdrawal sides of the UTC.(Priority: High. First reported 2011. Status: Partially adopted.)
- The MMU recommends allocating the energy uplift credits paid to units scheduled by PJM as must run in the day-ahead energy market for reasons other than voltage/reactive or black start services as a reliability charge to real-time load, real-time exports and real-time wheels. (Priority: Medium. First reported 2014. Status: Not adopted. Stakeholder process.)
- The MMU recommends that the total cost of providing reactive support be categorized and allocated as reactive services. Reactive services credits should be calculated consistent with the balancing generator credit calculation. (Priority: Medium. First reported 2012. Status: Not adopted. Stakeholder process.)
- The MMU recommends including real-time exports and real-time wheels in the allocation of the cost of providing reactive support to the 500 kV system or above, in addition to real-time load. (Priority: Low. First reported 2013. Status: Not adopted.)
- The MMU recommends modifications to the calculation of lost opportunity costs credits paid to wind units. The lost opportunity costs credits paid to wind units should be based on the lesser of the desired output, the estimated output based on actual wind conditions and the capacity interconnection rights (CIRs). The MMU recommends that PJM allow wind units to request CIRs that reflect the maximum output wind units want to inject into the transmission system at any time. (Priority: Low. First reported 2012. Status: Partially adopted.)
- The MMU recommends that PJM clearly identify and classify all reasons for incurring uplift in the day-ahead and the real-time energy markets and the associated uplift charges in order to make all market participants aware of the reasons for these costs and to help ensure a long term solution to the issue of how to allocate the costs of uplift. (Priority: Medium. First reported 2011. Status: Partially adopted.)
- The MMU recommends that PJM revise the current uplift confidentiality rules in order to allow the disclosure of complete information about the level of uplift by unit and the detailed reasons for the level of uplift credits by unit in the PJM region. (Priority: High. First reported 2013. Status: Partially adopted.)[85]
- The MMU recommends that PJM eliminate the exemption for CTs and diesels from the requirement to follow dispatch in order to receive uplift. The performance of these resources should be evaluated in a manner consistent with all other resources (Priority: Medium. First reported 2018. Status: Adopted 2022.)

85 On September 7, 2018, PJM made a compliance filing for FERC Order No. 844 to publish unit specific uplift credits. The compliance filing was accepted by FERC on June 21, 2019. 166 FERC ¶ 61,210 (2019). PJM began posting unit specific uplift reports on May 1, 2019. 167 FERC ¶ 61,280 (2019).

Section 4 Conclusion

Competitive market outcomes result from energy offers equal to short run marginal costs that incorporate flexible operating parameters. When PJM permits a unit to include inflexible operating parameters in its offer and pays uplift based on those inflexible parameters, there is an incentive for the unit to remain inflexible. The rules regarding operating parameters should be implemented in a way that creates incentives for flexible operations rather than inflexible operations. The standard for paying uplift should be the maximum achievable flexibility, based on OEM standards for the benchmark new entrant unit (CONE unit) in the PJM Capacity Market demand (VRR) curve. Applying a weaker standard effectively subsidizes inflexible units by paying them based on inflexible parameters that result from lack of investment and that could be made more flexible. The result inflates uplift costs, suppresses energy prices, and is an incentive to inflexibility.

It is not appropriate to accept that inflexible units should be paid uplift based on inflexible offers. The question of why units make inflexible offers should be addressed directly. Are units inflexible because they are old and inefficient, because owners have not invested in increased flexibility or because they serve as a mechanism for the exercise of market power? The question of why the inflexible unit was built, whether it was built under cost of service regulation and whether it is efficient to retain the unit should be answered directly. The question of how to provide market incentives for investment in flexible units and for investment in increased flexibility of existing units should be addressed directly. The question of whether inflexible units should be paid uplift at all should be addressed directly. Marginal cost pricing without paying uplift to inflexible units would create incentives for market participants to provide flexible solutions including replacing inefficient units with flexible, efficient units.

Implementing combined cycle modeling, to permit the energy market model optimization to take advantage of the versatility and flexibility of combined cycle technology in commitment and dispatch, would provide significant flexibility without requiring a distortion of the market rules. But such modeling should not be used as an excuse to eliminate market power mitigation or an excuse to permit inflexible offers to be paid uplift. There are defined steps that could and should be taken immediately to improve the modeling of combined cycle plants that do not require investment in combined cycle modeling software, including modeling soak time, and accurately accounting for transition times to power augmentation offer segments.

The reduction of uplift payments should not be a goal to be achieved at the expense of the fundamental logic of the LMP system. For example, the use of closed loop interfaces to reduce uplift should be eliminated because it is not consistent with LMP fundamentals and constitutes a form of subjective price setting. The same is true of what PJM terms its CT price setting logic. The same is true of fast start pricing. The same is true of PJM's proposal to modify the ORDC in order to increase energy prices and reduce uplift.

Accurate short run price signals, equal to the short run marginal cost of generating power, provide market incentives for cost minimizing production to all economically dispatched resources and provide market incentives to load based on the marginal cost of additional consumption. The objective of efficient short run price signals is to minimize system production costs, not to minimize uplift. Repricing the market to reflect commitment costs will create a tradeoff between minimizing production costs and reduction of uplift. The tradeoff will exist because when commitment costs are included in prices, the price signal no longer equals the short run marginal cost and therefore no longer provides the correct signal for efficient behavior for market participants making decisions on the margin, whether resources, load, interchange transactions, or virtual traders. This tradeoff now exists based on PJM's recently implemented fast start pricing proposal (limited convex hull pricing). Fast start pricing was approved by FERC and implemented on September 1, 2021.[86] Fast start pricing affects uplift calculations by introducing a new category of uplift in the balancing market, and changing the calculation of uplift in the day-ahead market.

When units receive substantial revenues through energy uplift payments, these payments are not fully transparent to the market, in part because of the current confidentiality rules. As a result, other market participants, including

86 See 173 FERC ¶ 61,244 (2020).

generation and transmission developers, do not have the opportunity to compete to displace them. As a result, substantial energy uplift payments to a concentrated group of units and organizations have persisted. FERC Order No. 844 authorized the publication of unit specific uplift payments for credits incurred after July 1, 2019.[87] However, Order No. 844 failed to require the publication of unit specific uplift credits for the largest units receiving significant uplift payments, inflexible steam units committed for reliability in the day-ahead market.

Uplift payments could be significantly reduced by reversing many of the changes that have been made to the original basic uplift rules. The goal of uplift is to ensure that competitive energy and ancillary service market outcomes do not require efficient resources operating for the PJM system, at the direction of PJM, to operate at a loss. In the original PJM design, uplift was calculated on a daily basis, including all costs and net revenues. But that rule was changed to use only segments of the day. The result is to overstate uplift payments because units may be paid uplift for a day in which their net revenues exceed their costs. In the original PJM design, all net revenues from energy and ancillary services were an offset to uplift payments. But that rule was changed to eliminate net revenue from the regulation market. The result is to overstate uplift payments, for no logical reason.

Uplift payments could also be significantly reduced to a more efficient level by eliminating all day-ahead operating reserve credits. It is illogical and unnecessary to pay units day-ahead operating reserve credits because units do not incur any costs to run and any revenue shortfalls are addressed by balancing generator credits.

On July 16, 2020, following its investigation of the issue, the Commission ordered PJM to revise its rules so that UTCs are required to pay uplift on the withdrawal side (DEC) only.[88] The uplift payments for UTCs began on November 1, 2020. The MMU has had a longstanding recommendation that UTCs be required to pay uplift on both the injection and withdrawal sides.[89]

On November 1, 2022, the longstanding rule which exempted CTs from the otherwise generally applicable rules governing the payment of uplift credits, was terminated.[90] Prior to November 1, CTs were paid uplift regardless of their output and regardless of whether they followed dispatch. As a result of the rule, CTs had no incentive to follow PJM dispatch signals and received excessive uplift credits.

The rule change is expected to reduce balancing generator reserve credits paid to combustion turbines and diesel engines. The rule change is expected to have no impact on lost opportunity cost credits, dispatch differential lost opportunity cost credits, reactive service credits, and black start credits, despite CTs also receiving a large share of those credit categories. No is expected to these categories because the calculation for these credit categories is not based on distinguishing the PJM calculated desired MW from the actual generation.

PJM needs to pay substantially more attention to the details of uplift payments including accurately tracking whether units are following dispatch, identifying the actual need for units to be dispatched out of merit and determining whether better definitions of constraints would be a more market based approach. PJM pays uplift to units even when they do not operate as requested by PJM, i.e. when units do not follow dispatch. PJM uses dispatcher logs as a primary screen to determine if units are eligible for uplift regardless of how they actually operate or if they followed the PJM dispatch signal. The reliance on dispatcher logs for this purpose is impractical, inefficient, and incorrect. PJM needs to define and implement systematic and verifiable rules for determining when units are following dispatch as a primary screen for eligibility for uplift payments. PJM should not pay uplift to units that do not follow dispatch.

The MMU notifies PJM and generators of instances in which, based on the PJM dispatch signal and the real-time output of the unit, it is clear that the unit did

87 On June 21, 2019, FERC accepted PJM's Order No. 844 compliance filing. 166 FERC ¶ 61,210 (2019). The filing stated that PJM would begin posting unit specific uplift reports on May 1, 2019. On April 8, 2019, PJM filed for an extension on the implementation date of the zonal uplift reports and unit specific uplift reports to July 1, 2019. On June 28, 2019, FERC accepted PJM's request for extension of effective dates. 167 FERC ¶ 61,280 (2019).

88 See 172 FERC ¶ 61,046 (2020).

89 On October 17, 2017, PJM filed a proposed tariff change at FERC to allocate uplift to UTC transactions in the same way uplift is allocated to other virtual transactions, as a separate injection and withdrawal deviation. FERC rejected the proposed tariff change. See 162 FERC ¶ 61,019 (2018).

90 See PJM "Manual 28: Operating Reserve Accounting," Rev. 88 (Oct. 1, 2022).

not operate as requested by PJM. The MMU sends requests for resettlements to PJM to make the units with the most extreme overpayments ineligible for uplift credits. Since 2018, the MMU has requested that PJM require the return of $15.1 million of incorrect uplift credits of which PJM has resettled only $1.4 million over the last two years, or 9.2 percent. In addition, PJM has refused to accept the return of incorrectly paid uplift credits by generators when the MMU has identified such cases.

While energy uplift charges are an appropriate part of the cost of energy, market efficiency would be improved by ensuring that the level and variability of these charges are as low as possible consistent with the reliable operation of the system and consistent with pricing at short run marginal cost. The goal should be to minimize the total incurred energy uplift charges and to increase the transactions over which those charges are spread in order to reduce the impact of energy uplift charges on markets. The result would be to reduce the level of per MWh charges, to reduce the uncertainty associated with uplift charges and to reduce the impact of energy uplift charges on decisions about how and when to participate in PJM markets. The result would also be to increase incentives for flexible operation and to decrease incentives for the continued operation of inflexible and uneconomic resources. PJM does not need a new flexibility product. PJM needs to provide incentives to existing and new entrant resources to unlock the significant flexibility potential that already exists, to end incentives for inflexibility and to stop creating new incentives for inflexibility.

Overview: Section 5, Capacity Market

RPM Capacity Market

Market Design

The Reliability Pricing Model (RPM) Capacity Market is a forward looking, annual, locational market, with a must offer requirement for Existing Generation Capacity Resources and a must buy requirement for load, with performance incentives, that includes clear market power mitigation rules and that permits the direct participation of demand-side resources.[91] Currently, intermittent and storage resources are exempt from the must offer requirement, although that is not a viable long term design element for the capacity market. The fundamental goal of the must offer requirement is to ensure that the capacity market works and therefore that the energy market works, given that LSEs have a must buy obligation.

Under RPM, capacity obligations are annual.[92] Base Residual Auctions (BRA) are held for delivery years that are three years in the future. First, Second and Third Incremental Auctions (IA) are held for each delivery year.[93] First, Second, and Third Incremental Auctions are conducted 20, 10, and three months prior to the delivery year.[94] A Conditional Incremental Auction may be held if there is a need to procure additional capacity resulting from a delay in a planned large transmission upgrade that was modeled in the BRA for the relevant delivery year.[95]

The 2023/2024 RPM Third Incremental Auction was conducted in the first three months of 2023. The 2024/2025 RPM Base Residual Auction was conducted in 2022, but the results were not posted until February 27, 2023, due to an issue with the DPL South reliability requirement.[96]

RPM prices are locational and may vary depending on transmission constraints and local supply and demand conditions.[97] Existing generation that qualifies as a capacity resource must be offered into RPM auctions, except for resources owned by entities that elect the fixed resource requirement (FRR) option, and, as a result of Capacity Performance rule changes, except for intermittent and capacity storage resources including hydro. Participation by LSEs is mandatory, except for those entities that elect the FRR option. There is an administratively determined demand curve that defines scarcity pricing levels and that, with the supply curve derived from capacity offers, determines market prices in each BRA. RPM rules provide performance incentives for generation, including

91 The terms *PJM Region*, *RTO Region* and *RTO* are synonymous in this report and include all capacity within the PJM footprint.

92 Effective for the 2020/2021 and subsequent delivery years, the RPM market design incorporated seasonal capacity resources. Summer period and winter period capacity must be matched either through commercial aggregation or through the optimization in equal MW amounts in the LDA or the lowest common parent LDA.

93 See 126 FERC ¶ 61,275 at P 86 (2009).

94 See Letter Order, FERC Docket No. ER10-366-000 (January 22, 2010).

95 See 126 FERC ¶ 61,275 at P 88 (2009). There have been no Conditional Incremental Auctions.

96 On December 23, 2022, PJM filed revisions to the PJM market rules in Docket No. ER23-729-000 and contemporaneously filed a complaint in Docket No. EL23-19-000 seeking the same revisions. By order issued February 21, 2023, PJM's revisions were accepted and the complaint was dismissed as moot. 182 FERC ¶ 61,109.

97 Transmission constraints are local capacity import capability limitations (low capacity emergency transfer limit (CETL) margin over capacity emergency transfer objective (CETO)) caused by transmission facility limitations, voltage limitations or stability limitations.

the requirement to submit generator outage data and the linking of capacity payments to the level of unforced capacity. The experience with Winter Storm Elliott (Elliott) has made clear that the extremely high penalties created in the CP model are not an effective incentive. Under RPM there are explicit market power mitigation rules that define structural market power, that define offer caps based on the marginal cost of capacity, and that have flexible criteria for competitive offers by new entrants. Market power mitigation is effective only when these definitions are up to date and accurate. Demand resources and energy efficiency resources may be offered directly into RPM auctions and receive the clearing price without mitigation.

Market Structure

- **RPM Installed Capacity.** In the first three months of 2023, RPM installed capacity decreased 77.0 MW or 0.0 percent, from 183,388.8 MW on January 1, to 183,311.8 MW on March 31. Installed capacity includes net capacity imports and exports and can vary on a daily basis.
- **Reserves.** For the 2024/2025 RPM Base Residual Auction, the sum of cleared MW that were considered categorically exempt from the must offer requirement and the cleared MW of DR is 16,403.2 MW, or 97.2 percent of required reserves and 65.7 percent of total reserves. These results suggest that the required reserve margin and the actual reserve margin be considered carefully along with the obligations of the resources that the reserve margin assumes will be available.
- **RPM Installed Capacity by Fuel Type.** Of the total installed capacity on March 31, 2023, 48.0 percent was gas; 23.4 percent was coal; 17.4 percent was nuclear; 4.6 percent was hydroelectric; 2.8 percent was oil; 1.9 percent was wind; 0.4 percent was solid waste; and 1.5 percent was solar.
- **Market Concentration.** In the 2024/2025 RPM Base Residual Auction, all participants in the total PJM market as well as the LDA RPM markets failed the three pivotal supplier (TPS) test.[98] In the 2023/2024 RPM Third Incremental Auctions, 36 participants out of 51 participants in the total PJM market passed the TPS test, eight participants out of 17 participants in the MAAC LDA market passed the TPS test, and all participants in the EMAAC and BGE LDA markets failed the TPS test. Offer caps were applied to all sell offers for resources which were subject to mitigation when the capacity market seller did not pass the test, the submitted sell offer exceeded the defined offer cap, and the submitted sell offer, absent mitigation, increased the market clearing price.[99] [100] [101]
- **Imports and Exports.** Of the 1,527.1 MW of imports in the 2024/2025 RPM Base Residual Auction, 1,397.6 MW cleared. Of the cleared imports, 820.4 MW (58.7 percent) were from MISO.
- **Demand-Side and Energy Efficiency Resources.** Capacity in the RPM load management programs was 14,027.0 MW for June 1, 2022, as a result of cleared capacity for demand resources and energy efficiency resources in RPM auctions for the 2022/2023 Delivery Year (14,601.0 MW) less purchases of replacement capacity (574.0 MW).

Market Conduct

- **2024/2025 RPM Base Residual Auction.** Of the 964 generation resources that submitted Capacity Performance offers, the MMU calculated unit specific offer caps for 22 generation resources (2.3 percent).
- **2023/2024 RPM Third Incremental Auction.** Of the 250 generation resources that submitted Capacity Performance offers, the MMU calculated unit specific offer caps for five generation resources (2.0 percent).

Market Performance

- The 2023/2024 RPM Third Incremental Auction was conducted in the first three months of 2023. The 2024/2025 RPM Base Residual Auction was conducted in 2022, but the results were not posted until February 27, 2023, due to an issue with the DPL South reliability requirement. The weighted average capacity price for the 2022/2023 Delivery Year is $72.33 per MW-day, including all RPM auctions for the 2022/2023

98 There are 27 Locational Deliverability Areas (LDAs) identified to recognize locational constraints as defined in "Reliability Assurance Agreement Among Load Serving Entities in the PJM Region," Schedule 10.1. PJM determines, in advance of each BRA, whether the defined LDAs will be modeled in the given delivery year using the rules defined in OATT Attachment DD § 5.10(a)(ii).

99 See OATT Attachment DD § 6.5.

100 Prior to November 1, 2009, existing DR and EE resources were subject to market power mitigation in RPM Auctions. See 129 FERC ¶ 61,081 at P 30 (2009).

101 Effective January 31, 2011, the RPM rules related to market power mitigation were changed, including revising the definition for Planned Generation Capacity Resource and creating a new definition for Existing Generation Capacity Resource for purposes of the must offer requirement and market power mitigation, and treating a proposed increase in the capability of a generation capacity resource the same in terms of mitigation as a Planned Generation Capacity Resource. See 134 FERC ¶ 61,065 (2011).

Delivery Year. The weighted average capacity price for the 2023/2024 Delivery Year is $42.00 per MW-day, including all RPM auctions for the 2023/2024 Delivery Year held through the first three months of 2023. The weighted average capacity price for the 2024/2025 Delivery Year is $40.73 per MW-day, including all RPM auctions for the 2024/2025 Delivery Year held through the first three months of 2023.

- For the 2022/2023 Delivery Year, RPM annual charges to load are $4.0 billion.
- In the 2024/2025 RPM Base Residual Auction, the market performance was determined to be competitive.

Part V Reliability Service

- Of the eight companies (24 units) that have provided service following deactivation requests, two companies (seven units) filed to be paid under the deactivation avoidable cost rate (DACR), the formula rate. The other six companies (17 units) filed to be paid under the cost of service recovery rate.

Generator Performance

- **Forced Outage Rates.** The average PJM EFORd in the first three months of 2023 was 4.7 percent, a decrease from 6.1 percent in the first three months of 2022.[102]
- **Generator Performance Factors.** The PJM aggregate equivalent availability factor in the first three months of 2023 was 86.6 percent, an increase from 86.5 percent in the first three months of 2022.

102 The generator performance analysis includes all PJM capacity resources for which there are data in the PJM generator availability data systems (GADS) database. Data was downloaded from the PJM GADS database on April 24, 2023. EFORd data presented in state of the market reports may be revised based on data submitted after the publication of the reports as generation owners may submit corrections at any time with permission from PJM GADS administrators.

Section 5 Recommendations[103]

Definition of Capacity

- The MMU recommends elimination of the key remaining components of the CP model because they interfere with competitive outcomes in the capacity market and create unnecessary complexity and risk. (Priority: High. First reported Q3, 2022. Status: Not adopted.)
- The MMU recommends the enforcement of a consistent definition of capacity resources. The MMU recommends that the requirement to be a physical resource be enforced and enhanced. The requirement to be a physical resource should apply at the time of auctions and should also constitute a commitment to be physical in the relevant delivery year. The requirement to be a physical resource should be applied to all resource types, including planned generation, demand resources and imports.[104] [105] (Priority: High. First reported 2013. Status: Not adopted.)
- The MMU recommends that DR providers be required to have a signed contract with specific customers for specific facilities for specific levels of DR at least six months prior to any capacity auction in which the DR is offered. (Priority: High. First reported 2016. Status: Not adopted.)
- The MMU recommends that Energy Efficiency Resources (EE) not be included in the capacity market because PJM's load forecasts now account for EE, unlike the situation when EE was first added to the capacity market.[106] (Priority: Medium. First reported 2016. Status: Not adopted.)
- The MMU recommends that intermittent resources, including storage, not be permitted to offer capacity MW based on energy deliveries that exceed their defined deliverability rights (CIRs). Only energy output for such resources below the designated CIR/deliverability level should be recognized in the definition of derated capacity (e.g. ELCC). Correctly defined derating factors will be lower than the CIRs required to meet

103 The MMU has identified serious market design issues with RPM and the MMU has made specific recommendations to address those issues. These recommendations have been made in public reports. See Table 5-2.
104 See also Comments of the Independent Market Monitor for PJM, Docket No. ER14-503-000 (December 20, 2013).
105 See "Analysis of Replacement Capacity for RPM Commitments: June 1, 2007 to June 1, 2019," <http://www.monitoringanalytics.com/reports/Reports/2019/IMM_Analysis_of_Replacement_Capacity_for_RPM_Commitments_June_1_2007_to_June_1_2019_20190913.pdf> (September 13, 2019).
106 "PJM Manual 19: Load Forecasting and Analysis," § 3.2 Development of the Forecast, Rev. 35 (Dec. 31, 2021).

those derating factors. (Priority: High. First reported 2021. Status: Not adopted.)

- The MMU recommends that PJM require all market participants to meet their deliverability requirements under the same rules. PJM should end the practice of giving away winter CIRs that appear to exist because other resources paid for the supporting network upgrades. (Priority: High. First reported 2017. Status: Not adopted.)[107]
- The MMU recommends that the must offer rule in the capacity market apply to all capacity resources. There is no reason to exempt intermittent and capacity storage resources, including hydro, and demand resources and energy efficiency resources from the must offer requirement. The same rules should apply to all capacity resources. (Priority: High. First reported 2021. Status: Not adopted.)

Market Design and Parameters

- The MMU recommends that PJM reevaluate the shape of the VRR curve. The shape of the VRR curve directly results in load paying substantially more for capacity than load would pay with a vertical demand curve. More specifically, the MMU recommends that the VRR curve be rotated half way towards the vertical demand curve at the reliability requirement for the current Quadrennial Review. (Priority: High. First reported 2021. Status: Partially adopted.)
- The MMU recommends that the maximum price on the VRR curve be defined as net CONE. (Priority: Medium. First reported 2019. Status: Not adopted.)
- The MMU recommends that the test for determining modeled Locational Deliverability Areas (LDAs) in RPM be redefined. A detailed reliability analysis of all at risk units should be included in the redefined model. (Priority: Medium. First reported 2013. Status: Not adopted.)
- The MMU recommends that PJM clear the capacity market based on nodal capacity resource locations and the characteristics of the transmission system consistent with the actual electrical facts of the grid. Absent a fully nodal capacity market clearing process, the MMU recommends that PJM use a non-nested model with all LDAs modeled including VRR curves for all LDAs. Each LDA requirement should be met with the capacity resources located within the LDA and exchanges from neighboring LDAs up to the transmission limit. LDAs should be allowed to price separate if that is the result of the LDA supply curves and the transmission constraints between LDAs. (Priority: Medium. First reported 2017. Status: Not adopted.)
- The MMU recommends the use of a forward looking energy and ancillary services (E&AS) net revenue offset rather than the backward looking E&AS net revenue offset currently in the tariff. Forward prices for energy prices and fuel costs are a better guide to market expectations of net revenues than an average of the actual net revenues for the last three years. (Priority: High. First reported 2014. Status: Not adopted.)[108]
- The MMU recommends that PJM reduce the number of incremental auctions to a single incremental auction held three months prior to the start of the delivery year and reevaluate the triggers for holding conditional incremental auctions. (Priority: Medium. First reported 2013. Status: Not adopted.)
- The MMU recommends that PJM not sell back any capacity in any IA procured in a BRA. If PJM continues to sell back capacity, the MMU recommends that PJM offer to sell back capacity in incremental auctions only at the BRA clearing price for the relevant delivery year. (Priority: Medium. First reported 2017. Status: Not adopted.)
- The MMU recommends changing the RPM solution method to explicitly incorporate the cost of uplift (make whole) payments in the objective function. (Priority: Medium. First reported 2014. Status: Not adopted.)
- The MMU recommends that the Fixed Resource Requirement (FRR) rules, including obligations and performance requirements, be revised and updated to ensure that the rules reflect current market realities and that FRR entities do not unfairly take advantage of those customers paying for capacity in the PJM capacity market. (Priority: Medium. First reported 2019. Status: Not adopted.)

107 This recommendation was first made in the 2020/2021 BRA report in 2017. See the "Analysis of the 2020/2021 RPM Base Residual Auction," <http://www.monitoringanalytics.com/reports/Reports/2017/IMM_Analysis_of_the_20202021_RPM_BRA_20171117.pdf> (November 11, 2017).

108 This recommendation was first made during the Quadrennial Review in 2014, including the PJM Capacity Senior Task Force (CSTF), the MRC and the MC. <https://www.pjm.com/committees-and-groups/closed-groups/cstf>.

- The MMU recommends that the value of CTRs should be defined by the total MW cleared in the capacity market, the internal MW cleared and the imported MW cleared, and not redefined later prior to the delivery year. (Priority: Medium. First reported 2021. Status: Not adopted.)
- The MMU recommends that the market clearing results be used in settlements rather than the reallocation process currently used, or that the process of modifying the obligations to pay for capacity be reviewed. (Priority: Medium. First reported 2021. Status: Not adopted.)
- The MMU recommends that PJM improve the clarity and transparency of its CETL calculations. The MMU also recommends that CETL for capacity imports into PJM be based on the ability to import capacity only where PJM capacity exists and where that capacity has a must offer requirement in the PJM Capacity Market. (Priority: Medium. First reported 2021. Status: Partially adopted 2022.)
- The MMU recommends that the value of CTRs be defined by the total MW cleared in the capacity market, the internal MW cleared and the imported MW cleared, and not redefined later prior to the delivery year. Capacity Transfer Rights (CTRs) are used to return capacity market congestion revenues to load, but the CTRs that result from market clearing prices and quantities are not included in final settlements for individual LDAs. MMU also recommends that the market clearing results be used in settlements rather than the reallocation process currently used or that the process of modifying the obligations to pay for capacity be reviewed. (Priority: High. First reported 2022. Status: Not adopted.)[109]

Offer Caps, Offer Floors, and Must Offer

- The MMU recommends using the lower of the cost or price-based energy market offer to calculate energy costs in the calculation of the historical net revenues which are an offset to gross ACR in the calculation of unit specific capacity resource offer caps based on net ACR. (Priority: Medium. First reported 2021. Status: Not adopted.)

109 This recommendation first made in the 2023/2024 BRA report in 2022. See "Analysis of the 2023/2024 RPM Base Residual Auction Revised," <http://www.monitoringanalytics.com/reports/Reports/2022/IMM_Analysis_of_the_20232024_RPM_Base_Residual_Auction_20221028.pdf> (October 28, 2022).

- The MMU recommends use of the Sustainable Market Rule (SMR) in order to protect competition in the capacity market from nonmarket revenues.[110] (Priority: High. First reported 2016. Status: Not adopted.)
- The MMU recommends that, as part of the MOPR unit specific standard of review, all projects be required to use the same basic modeling assumptions. That is the only way to ensure that projects compete on the basis of actual costs rather than on the basis of modeling assumptions.[111] (Priority: High. First reported 2013. Status: Not adopted.)
- The MMU recommends that modifications to existing resources be subject to market power related offer caps or MOPR offer floors and not be treated as new resources and therefore exempt. (Priority: Low. First reported 2012. Status: Not adopted.)
- The MMU recommends that the RPM market power mitigation rule be modified to apply offer caps in all cases when the three pivotal supplier test is failed and the sell offer is greater than the offer cap. This will ensure that market power does not result in an increase in uplift (make whole) payments for seasonal products. (Priority: Medium. First reported 2017. Status: Not adopted.)
- The MMU recommends that any combined seasonal resources be required to be in the same LDA and preferably at the same location, in order for the energy market and capacity market to remain synchronized and reliability metrics correctly calculated. (Priority: Medium. First reported 2021. Status: Not adopted.)
- The MMU recommends that the definition of avoidable costs in the tariff be corrected to be consistent with the economic definition. Avoidable costs are costs that are neither short run marginal costs, like fuel or consumables, nor fixed costs like depreciation and rate of return. Avoidable costs are the annual marginal costs of capacity and therefore

110 Brief of the Independent Market Monitor for PJM, Docket No. EL16-49, ER18-1314-000,-001; EL18-178 (October 2, 2018).
111 See 143 FERC ¶ 61,090 (2013) ("We encourage PJM and its stakeholders to consider, for example, whether the unit-specific review process would be more effective if PJM requires the use of common modeling assumptions for establishing unit-specific offer floors while, at the same time, allowing sellers to provide support for objective, individual cost advantages. Moreover, we encourage PJM and its stakeholders to consider these modifications to the unit-specific review process together with possible enhancements to the calculation of Net CONE."); see also, Comments of the Independent Market Monitor for PJM, Docket No. ER13-535-001 (March 25, 2013); Complaint of the Independent Market Monitor for PJM v. Unnamed Participant, Docket No. EL12-63-000 (May 1, 2012); Motion for Clarification of the Independent Market Monitor for PJM, Docket No. ER11-2875-000, et al. (February 17, 2012); Protest of the Independent Market Monitor for PJM, Docket No. ER11-2875-002 (June 2, 2011); Comments of the Independent Market Monitor for PJM, Docket Nos. EL11-20 and ER11-2875 (March 4, 2011).

the competitive offer level for capacity resources and therefore the market seller offer cap. Avoidable costs are the annual marginal costs of capacity whether a new resource or an existing resource. (Priority: Medium. First reported 2017. Status: Not adopted.)[112]

- The MMU recommends that capacity market sellers be required to explicitly request and support the use of minimum MW quantities (inflexible sell offer segments) and that the requests only be permitted for defined physical reasons. (Priority: Medium. First reported 2018. Status: Not adopted.)
- The MMU recommends that relatively small proposed increases in the capability of a Generation Capacity Resource be treated as an existing resource and subject to the corresponding market power mitigation rules and no longer be treated as planned and exempt from offer capping. (Priority: Medium. First reported 2012. Status: Not adopted.)[113]

Performance Incentive Requirements of RPM

- The MMU recommends that any unit not capable of supplying energy equal to its day-ahead must offer requirement (ICAP) be required to reflect an appropriate outage. (Priority: Medium. First reported 2009. Status: Not adopted.)
- The MMU recommends that retroactive replacement transactions associated with a failure to perform during a PAI not be allowed and that, more generally, retroactive replacement capacity transactions not be permitted. (Priority: Medium. First reported 2016. Status: Not adopted.)
- The MMU recommends that there be an explicit requirement that capacity resource offers in the day-ahead energy market be competitive, where competitive is defined to be the short run marginal cost of the units, including flexible operating parameters. (Priority: Low. First reported 2013. Status: Not adopted.)
- The MMU recommends that Capacity Performance resources be required to perform without excuses. Resources that do not perform should not be paid regardless of the reason for nonperformance. (Priority: High. First reported 2019. Status: Not adopted.)
- The MMU recommends that the market data posting rules be modified to allow the disclosure of expected performance, actual performance, shortfall and bonus MW during a PAI by area without the requirement that more than three market participants' data be aggregated for posting. (Priority: Low. First reported 2019. Status: Not adopted.)
- The MMU recommends that PJM require actual seasonal tests as part of the Summer/Winter Capability Testing rules, that the number of tests be limited, and that the ambient conditions under which the tests are performed be defined. (Priority: Medium. First reported Q1 2022. Status: Not adopted.)
- The MMU recommends that PJM select the time and day that a unit undergoes Net Capability Verification Testing, not the unit owner, and that this information not be communicated in advance to the unit owner. (Priority: Medium. First reported Q2 2022. Status: Not adopted.)

Capacity Imports and Exports

- The MMU recommends that all capacity imports be required to be deliverable to PJM load in an identified LDA, zonal or smaller, or explicit combinations of specific zones, e.g. MAAC, prior to the relevant delivery year to ensure that they are full substitutes for internal, physical capacity resources. Pseudo ties alone are not adequate to ensure deliverability to PJM load. (Priority: High. First reported 2016. Status: Not adopted.)
- The MMU recommends that all costs incurred as a result of a pseudo tied unit be borne by the unit itself and included as appropriate in unit offers in the capacity market. (Priority: High. First reported 2016. Status: Not adopted.)

112 This recommendation was first made in the 2023/2024 BRA report in 2022. See "Analysis of the 2023/2024 RPM Base Residual Auction Revised," <http://www.monitoringanalytics.com/reports/Reports/2022/IMM_Analysis_of_the_20232024_RPM_Base_Residual_Auction_20221028.pdf> (October 28, 2022).

113 This recommendation was first made in the 2014/2015 BRA report in 2012. See "Analysis of the 2014/2015 RPM Base Residual Auction," <http://www.monitoringanalytics.com/reports/Reports/2012/Analysis_of_2014_2015_RPM_Base_Residual_Auction_20120409.pdf> (April 9, 2012).

Deactivations/Retirements

- The MMU recommends that the notification requirement for deactivations be extended from 90 days prior to the date of deactivation to 12 months prior to the date of deactivation and that PJM and the MMU be provided 60 days rather than 30 days to complete their reliability and market power analyses. (Priority: Low. First reported 2012. Status: Partially adopted.)
- The MMU recommends that units recover all and only the incremental costs, including incremental investment costs, required by the Part V reliability service (RMR service) that the unit owner would not have incurred if the unit owner had deactivated its unit as it proposed. Customers should bear no responsibility for paying previously incurred costs, including a return on or of prior investments. (Priority: Low. First reported 2010. Status: Not adopted.)
- The MMU recommends elimination of the cost of service recovery rate in OATT Section 119, that Part V reliability service (RMR) should be provided under the deactivation avoidable cost rate in Part V, and that the cap on investment under the avoidable cost rate option be eliminated. The MMU also recommends specific improvements to the DACR provisions. (Priority: Medium. First reported 2017. Status: Not adopted.)

Section 5 Conclusion

The analysis of PJM Capacity Markets begins with market structure, which provides the framework for the actual behavior or conduct of market participants. The analysis examines participant behavior within that market structure. In a competitive market structure, market participants are constrained to behave competitively. In a market with endemic structural market power, effective market power mitigation rules are required in order to constrain market participants to behave competitively. The analysis examines market performance, measured by price and the relationship between price and marginal cost, that results from the interaction of market structure and participant behavior.

The capacity market is, by design, always tight in the sense that total supply is generally only slightly larger than demand. The PJM Capacity Market is a locational market and local markets can and do have different supply demand balances than the aggregate market. While the market may be long at times, that is not the equilibrium state. Capacity in excess of demand is not sold and, if it does not earn or does not expect to earn adequate revenues in future capacity markets, or in other markets, or does not have value as a hedge, may be expected to retire, provided the market sets appropriate price signals to reflect the availability of excess supply. The demand for capacity includes expected peak load plus a reserve margin, and points on the demand curve, called the Variable Resource Requirement (VRR) curve, exceed peak load plus the reserve margin. The shape of the VRR curve results in the purchase of excess capacity and higher payments by customers. The impact of the VRR curve shape used in the 2023/2024 BRA compared to a vertical demand curve was a significant increase in customer payments for load as a result of buying more capacity than needed for reliability and paying a price above the competitive level as a result. The defined reliability goal is to have total supply greater than or equal to the defined demand for capacity. The level of purchased demand under RPM has generally exceeded expected peak load plus the target reserve margin, resulting in reserve margins that exceed the target. Demand for capacity is almost entirely inelastic because the market rules require loads to purchase their share of the system capacity requirement. The VRR demand curve is everywhere inelastic. The result is that any supplier that owns more capacity than the typically small difference between total supply and the defined demand is individually pivotal and therefore has structural market power. Any supplier that, jointly with two other suppliers, owns more capacity than the difference between supply and demand either in aggregate or for a local market is jointly pivotal and therefore has structural market power.

For the 2024/2025 RPM Base Residual Auction, the level of committed demand resources (8,083.9 MW UCAP) almost equals the entire level of excess capacity (8,086.8 MW). This is consistent with PJM effectively not relying on demand response for reliability in actual operations. The excess is a result of the flawed rules permitting the participation of inferior demand side resources in the capacity market. Maintaining the persistent excess has meant that PJM markets have never experienced the results of reliance on demand side resources as part of the required reserve margin, rather than as excess above the required reserve margin. PJM markets have never experienced the implications of the definition of demand side resources as a purely emergency capacity resource that triggers a PAI whenever called and can set prices at shortage levels simply by being called.

The market design for capacity leads to structural market power in the capacity market. The capacity market is unlikely ever to approach a competitive market structure in the absence of a substantial and unlikely structural change that results in much greater diversity of ownership. Market power is and will remain endemic to the structure of the PJM Capacity Market. Nonetheless a competitive outcome can be assured by appropriate market power mitigation rules. Detailed market power mitigation rules are included in the PJM Open Access Transmission Tariff (OATT or Tariff). Reliance on the RPM design for competitive outcomes means reliance on the market power mitigation rules. Attenuation of those rules means that market participants are not able to rely on the competitiveness of the market outcomes. The market power rules applied in the 2021/2022 BRA and the 2022/2023 BRA were significantly flawed, as illustrated by the results of the 2021/2022 BRA and the 2022/2023 BRA.[114] [115] Competitive outcomes require continued improvement of the rules and ongoing monitoring of market participant behavior and market performance. The incorrect definition of the offer caps in the 2021/2022 BRA and the 2022/2023 BRA resulted in noncompetitive offers and a noncompetitive outcome. The market power rules were corrected by the Commission in an order issued on September 2, 2021, but the modified market power rules were not implemented in the 2022/2023 BRA.[116] [117] The result was that capacity market prices were above the competitive level in the 2022/2023 BRA. In addition, the inclusion of offers that were not consistent with the defined terms of the Minimum Offer Price Rule (MOPR) based on the MMU's review, but were accepted by PJM, had a significant impact on the auction results in the 2022/2023 BRA.

The implementation of the market power mitigation rules effective September 2, 2021, that corrected the definition of the market seller offer cap in the 2023/2024 BRA resolved the market power issues from the prior two BRAs. The results of the 2023/2024 BRA and the 2024/2025 BRA were competitive.

In the capacity market, as in other markets, market power is the ability of a market participant to increase the market price above the competitive level or to decrease the market price below the competitive level. In order to evaluate whether actual prices reflect the exercise of market power, it is necessary to evaluate whether market offers are consistent with competitive offers.

The definition of the market seller offer cap was changed with the introduction of the Capacity Performance (CP) rules, from offer caps based on the marginal cost of capacity to offer caps based on Net CONE. But the CP market seller offer cap was based on strong assumptions that are not correct. The derivation of the CP market seller offer cap was based on PJM's assertion that the target price of the capacity market should be Net CONE, and simply assumed the answer. The logic underlying the CP market seller offer cap was circular. The CP market seller offer cap was incorrectly and significantly overstated as a result.

PJM's filing of the CP design made clear that PJM was abandoning offer caps that were based on verifiable calculations of the marginal cost of providing capacity in favor of an approach that explicitly relied on wishful thinking about competitive forces resulting in competitive offers, despite the fact that the filing elsewhere recognized the high levels of concentration and the need to protect against market power in the capacity market.[118] PJM ignored the economic logic of marginal cost. PJM simply asserted that Net CONE was the target clearing price of the capacity market. PJM's filing explicitly stated that "By design, over time the marginal offer needed to clear the market will be priced at Net CONE, and all other resources that clear the market will be compensated at that Net CONE price."[119] PJM did not include a derivation of the offer cap in its CP filing, but simply asserted that Net CONE was the definition

114 See "Analysis of the 2021/2022 RPM Base Residual Auction - Revised," <http://www.monitoringanalytics.com/reports/Reports/2018/IMM_Analysis_of_the_20212022_RPM_BRA_Revised_20180824.pdf> (August 24, 2018).

115 See "Analysis of the 2022/2023 RPM Base Residual Auction," <https://www.monitoringanalytics.com/reports/Reports/2022/IMM_Analysis_of_the_20222023_RPM_BRA_20220222.pdf> (February 22, 2022).

116 Complaint of the Independent Market Monitor for PJM, Docket No. EL19-47 (February 21, 2019) ("IMM MSOC Complaint").

117 176 FERC ¶ 61,137 (2021); 178 FERC ¶ 61,121 (2022); *appeal pending*, Vistra Corp., et al. v. FERC, USCA D.C. Circuit Case No. 21-1214.

118 See "Reforms to the Reliability Pricing Market ("RPM") and Related Rules in the PJM Open Access Transmission Tariff ("Tariff") and Reliability Assurance Agreement Among Load Serving Entities ("RAA")," ("CP Filing"), Docket No. ER15-623, December 12, 2014; See, for example, page 54 and page 58.

119 See page 55 of CP Filing.

of a competitive offer.[120] There was not a single reference to opportunity cost as the basis for the market seller offer cap in the PJM filing.

In subsequent filings, PJM included the mathematical derivation of the market seller offer cap.[121] But the circular logic of the derivation inevitably concluded that Net CONE times B was the competitive offer. There were two key assumptions that led to that result. The derivation started by assuming that Net CONE was the target clearing price for the capacity market. PJM stated, in explaining the penalty rate, "Net CONE is the proper measure of the value of capacity."[122] That assumption/assertion was the basis for using Net CONE as the penalty rate. The penalty rate, adjusted for the reduced obligation defined by B, became the market seller offer cap. In addition to assuming the answer by setting the penalty rate based on net CONE, the second key counterfactual assumption was that capacity resources have the ability to costlessly switch between capacity resource status and energy only status.

The mathematical derivation also included some additional unsupported and incorrect assumptions: there are a reasonably expected number of PAI; the number of PAI used in the calculation of the nonperformance charge rate is the same as the expected PAI (360); the number of performance intervals that define the total payments must equal the denominator of the performance penalty rate; the bonus payment rate for units that overperform equals the penalty rate for units that underperform; and penalties are imposed by PJM for all cases of noncompliance as defined in the tariff and there are no excuses.

Those assumptions were not even close to being correct for the 2022/2023 BRA and Net CONE times B was not the correct offer cap as a result.

The MMU supported the modified CP filing and prepared the mathematical appendix.[123] But, after evaluating the offer behavior and results of the capacity market auctions under CP and the actual PAI evidence and the failure to include updated PAI data in the definition of the offer cap, it became clear to the MMU that the CP model was a mistake.[124] The market seller offer cap of Net CONE times B was ultimately a failed experiment based on the third demonstrably false assumption that competitive forces in the PJM Capacity Market would produce competitive outcomes despite an offer cap that was above the competitive level. The structure of the PJM Capacity Market is not competitive and the purpose of market power mitigation is to produce competitive results despite that fact. The Net CONE times B offer cap assumed competition where it did not exist and led to noncompetitive outcomes and led to customers being overcharged by a combined $1.454 billion in the 2021/2022 and 2022/2023 BRAs.[125] The logical circularity of the argument as well as the fact that key assumptions are incorrect, means that the CP market seller offer cap was not based on economics or logic or math.

The correct definition of a competitive offer is the marginal cost of capacity, net ACR, where ACR includes an explicit accounting for the costs of mitigating risk, including the risk associated with capacity market nonperformance penalties, and the relevant costs of acquiring fuel, including natural gas. In response to a complaint filed by the MMU, the Commission replaced the Net CONE times B market seller offer cap with an ACR offer cap in the September 2nd Order.[126] [127]

The MMU recommends elimination of the key remaining components of the CP model because they interfere with competitive outcomes in the capacity market and create unnecessary complexity and risk. The use of Net CONE as the basis for the penalty rate is unsupported by economic logic. The use of Net CONE to establish penalties is a form of arbitrary administrative pricing that creates arbitrarily high risk for generators, creates complexity in the calculation of CPQR and ultimately raises the price of capacity. Rather than penalizing capacity resources for nonperformance, capacity resources should be paid the daily price of capacity only to the extent that they are available

120 PJM did not multiply Net CONE by B in its CP filing of December 12, 2014.
121 For a detailed derivation, *see* Errata to February 25, 2015 Answer and Motion for Leave to Answer of the Independent Market Monitor for PJM Interconnection, L.L.C., Docket No. ER15-623, et al. (February 27, 2015).
122 See page 43 of CP Filing.
123 See PJM Response to Deficiency Notice, ER15-623-001, et al. (April 10, 2015); Comments of the Independent Market Monitor for PJM, Docket No. ER15-623-001, et al. (April 15, 2015).
124 Brief of the Independent Market Monitor for PJM, EL19-47-000 (April 28, 2021); see also Comments of the Independent Market Monitor, Docket No. ER15-623, EL15-29 and EL19-47 (December 13, 2019); Comments of the Independent Market Monitor, Docket No. ER15-623, EL15-29 and EL19-47 (December 17, 2020).
125 See "Analysis of the 2021/2022 RPM Base Residual Auction - Revised," <http://www.monitoringanalytics.com/reports/Reports/2018/IMM_Analysis_of_the_20212022_RPM_BRA_Revised_20180824.pdf> (August 24, 2018) and "Analysis of the 2022/2023 RPM Base Residual Auction," <http://www.monitoringanalytics.com/reports/Reports/2022/IMM_Analysis_of_the_20222023_RPM_BRA_20220222.pdf>.
126 Complaint of the Independent Market Monitor for PJM, Docket No. EL19-47, February 21, 2019 ("IMM MSOC Complaint").
127 174 FERC ¶ 61,212; 176 FERC ¶ 61,137; *order on reh'g*, 178 FERC ¶ 61,121.

to produce energy or provide reserves, as required by PJM on a daily/hourly basis, based on their cleared capacity (ICAP). This is a positive performance incentive based on the market price of capacity rather than a penalty based on an arbitrary assumption. This would mean that capacity resources are paid to provide energy and reserves based on their full ICAP and are not paid a bonus for doing so. The reduced payments for capacity would directly reduce customers' bills for capacity. This would also end the pretense that there will be penalty payments to fund bonus payments. This would also end the need for complex CPQR calculations based on the penalty rate and assumptions about the number and timing of PAI. CP has not worked as the theory suggested. There have been only de minimis and generally very local PAI, largely excused nonperformance and de minimis bonus payments. The actual performance standards were unacceptably weakened in the CP model. The standard of performance in the CP model is B * (1 – EFORd) for a unit, where B is the balancing ratio and EFORd is the forced outage rate. For example, if B were 80 percent, the actual required performance for a unit with a 10 percent EFORd would be only 72 percent of ICAP (.80 * .90). For units with high historical forced outage rates, the required performance is even lower. The obligation to perform should equal the full ICAP value of a unit, consistent with the associated must offer obligation in the energy market for capacity resources.

The fundamental mistake of the CP design was to attempt to recreate energy market incentives in the capacity market. The CP model was an explicit attempt to bring energy market shortage pricing into the capacity market design. The CP model was designed on the assumption that shortage prices in the energy market were not high enough and needed to be increased via the capacity market. The CP design focused on a small number of critical hours (performance assessment hours or PAH, translated into five minute intervals as PAI) and imposed large penalties on generators that failed to produce energy only during those hours. But the use of capacity market penalties rather than energy market incentives created risk. While there are differences of opinion about how to value the risk, this CP risk is not risk that is fundamental to the operation of a wholesale power market. This is risk created by the CP design in order, in concept, to provide an incentive to produce energy during high demand hours that is even higher than the energy market incentive, amplified by an operating reserve demand curves (ORDC). The potential risk created by CP is not limited to risk for individual generators, but extends to the viability of the market. If penalties create bankruptcies that threaten the viability of required energy output from the affected units, there is a risk to the market.

Winter storm Elliott provided the first real test of the CP design. Elliott showed that the CP design does not provide effective incentives. There was an extremely high forced outage level during Elliott despite the incentives and despite the fact that the effectively uncapped market seller offer cap (MSOC) was in place (Net CONE times B) for RPM auctions conducted for the 2022/2023 Delivery Year. In addition, it has been clear from prior, very brief and local PAI events that the process of defining excuses and retroactive replacement transactions, imposing penalties and paying bonuses is complex and very difficult to administer, and includes substantial subjective elements. PAI incentives are not effective market incentives. PAI incentives are administrative and nonmarket incentives not compatible with an effective market design. The energy market clearing, in contrast, is transparent and efficient and timely. While there are issues with the details of energy market pricing that must be addressed, including shortage pricing, the energy market does not include or create the significant and long lasting uncertainty created by the PAI rules as exhibited most dramatically by the results of Elliott. The PAI design creates an administrative process that adds unacceptable uncertainty to the process and that can never approach the effectiveness of the energy market in providing price signals and timely settlement.

The MMU concludes that the results of the 2024/2025 RPM Base Residual Auction were competitive. A competitive offer in the capacity market is equal to net ACR.[128] The ACR values were based on data provided by the participants and were consistent with competitive offers for the relevant capacity.

The MMU also concludes that market prices were significantly affected by flaws in the capacity market rules and in the application of the capacity market rules by PJM, including the shape of the VRR curve; the overstatement

128 174 FERC ¶ 61,212 ("March 18th Order") at 65.

of intermittent MW offers; the inclusion of sell offers from DR; and capacity imports.

The MMU also concludes that, although not an issue in the 2024/2025 Base Residual Auction, the rules permit the exercise of market power without mitigation for seasonal products through uplift payments for noncompetitive offers, rather than through higher prices.[129] Although the impact did not arise in the 2024/2025 Base Residual Auction, the issue should be addressed immediately in order to prevent the impact from increasing and because the solution is simple.

Changes to the capacity market design have addressed some but not all of the significant recommendations made by the MMU in prior reports. The MMU had recommended the elimination of the 2.5 percent demand adjustment (Short-Term Resource Procurement Target). The MMU had recommended that the performance incentives in the capacity market design be strengthened. The MMU had recommended that generation capacity resources pay penalties if they fail to produce energy when called upon during any of the hours defined as critical. The MMU had recommended that the net revenue calculation used by PJM to calculate the Net Cost of New Entry (CONE) VRR parameter reflect the actual flexibility of units in responding to price signals rather than using assumed fixed operating blocks that are not a result of actual unit limitations. The MMU had recommended that all capacity imports be required to be pseudo tied in order to ensure that imports are as close to full substitutes for internal, physical capacity resources as possible. The MMU had recommended that the definition of demand side resources be modified in order to ensure that such resources are full substitutes for and provide the same value in the capacity market as generation resources, although this recommendation has not been incorporated in PJM rules. The MMU had recommended that both the Limited and the Extended Summer DR products be eliminated and that the restrictions on the availability of Annual DR be eliminated in order to ensure that the DR product has the same unlimited obligation to provide capacity year round as Generation Capacity Resources. The MMU had recommended that the EE addback calculation be corrected. The MMU had recommended that the default Avoidable Cost Rate (ACR) escalation method be modified in order to ensure accuracy and eliminate double counting.

The MMU is required to identify market issues and to report them to the Commission and to market participants. The Commission decides on any action related to the MMU's findings.

The MMU has identified serious market design issues with RPM and the MMU has made specific recommendations to address those issues.[130] [131] [132] [133] [134] [135] [136] [137] [138] In 2022 and 2023, the MMU prepared a number of RPM related reports and testimony, shown in Table 5-2.

The PJM markets have worked to provide incentives to entry and to retain capacity. PJM had excess reserves of 6,596.3 ICAP MW on June 1, 2022, and will have excess reserves of 8,896.3 ICAP MW on June 1, 2023, based on current positions.[139] A majority of capacity investments in PJM were financed by market sources.[140] Of the 46,697.0 MW of additional capacity that cleared in RPM auctions for the 2007/2008 through 2022/2023 Delivery Years, 34,853.8 MW (74.6 percent) were based on market funding. Of the 3,794.3 MW of additional capacity that cleared in RPM auctions for the 2023/2024 through 2024/2025 Delivery Years, 3,557.4 MW (93.8 percent) were based on market funding. Those investments were made based on the assumption that markets would be allowed to work and that inefficient units would exit.

129 PJM uses various terms for uplift including make whole payments (often used in the capacity market) and operating reserve payments (often used in the energy market). The term uplift is used in this report to refer to out of market payments made by PJM to market participants in addition to market revenues.

130 See "Analysis of the 2018/2019 RPM Base Residual Auction Revised," <http://www.monitoringanalytics.com/reports/Reports/2016/IMM_Analysis_of_the_20182019_RPM_Base_Residual_Auction_20160706.pdf> (July 6, 2016).

131 See "Analysis of the 2019/2020 RPM Base Residual Auction Revised," <http://www.monitoringanalytics.com/reports/Reports/2016/IMM_Analysis_of_the_20192020_RPM_BRA_20160831-Revised.pdf> (August 31, 2016).

132 See "Analysis of the 2020/2021 RPM Base Residual Auction," <http://www.monitoringanalytics.com/reports/Reports/2017/IMM_Analysis_of_the_20202021_RPM_BRA_20171117.pdf> (November 11, 2017).

133 See "Analysis of the 2021/2022 RPM Base Residual Auction - Revised," <http://www.monitoringanalytics.com/reports/Reports/2018/IMM_Analysis_of_the_20212022_RPM_BRA_Revised_20180824.pdf> (August 24, 2018).

134 See "Analysis of the 2022/2023 RPM Base Residual Auction," <https://www.monitoringanalytics.com/reports/Reports/2022/IMM_Analysis_of_the_20222023_RPM_BRA_20220222.pdf> (February 22, 2022).

135 See "Analysis of the 2023/2024 RPM Base Residual Auction," <https://www.monitoringanalytics.com/reports/Reports/2022/IMM_Analysis_of_the_20232024_RPM_Base_Residual_Auction_20221028.pdf> (October 28, 2022).

136 See "Analysis of Replacement Capacity for RPM Commitments: June 1, 2007 to June 1, 2017," <http://www.monitoringanalytics.com/reports/Reports/2017/IMM_Report_on_Capacity_Replacement_Activity_4_20171214.pdf> (December 14, 2017).

137 See "Analysis of Replacement Capacity for RPM Commitments: June 1, 2007 to June 1, 2019," <http://www.monitoringanalytics.com/reports/Reports/2019/IMM_Analysis_of_Replacement_Capacity_for_RPM_Commitments_June_1_2007_to_June_1_2019_20190913.pdf> (September 13, 2019).

138 See "Analysis of the 2023/2024 RPM Base Residual Auction Revised," <http://www.monitoringanalytics.com/reports/Reports/2022/IMM_Analysis_of_the_20232024_RPM_Base_Residual_Auction_20221028.pdf> (October 28, 2022).

139 The calculated reserve margin for June 1, 2023, does not account for cleared buy bids that have not been used in replacement capacity transactions.

140 "2020 PJM Generation Capacity and Funding Sources 2007/2008 through 2021/2022 Delivery Years," <http://www.monitoringanalytics.com/reports/Reports/2020/IMM_2020_PJM_Generation_Capacity_and_Funding_Sources_20072008_through_20212022_DY_20200915.pdf> (September 15, 2020).

It is essential that any approach to the PJM markets incorporate a consistent view of how the preferred market design is expected to provide competitive results in a sustainable market design over the long run. A sustainable market design means a market design that results in appropriate incentives to competitive market participants to retire units and to invest in new units over time such that reliability is ensured as a result of the functioning of the market.

A sustainable competitive wholesale power market must recognize three salient structural elements: state nonmarket revenues for renewable energy; a significant level of generation resources subject to cost of service regulation; and the structure and performance of the existing market based generation fleet.

In order to attract and retain adequate resources for the reliable operation of the energy market, revenues from PJM energy, ancillary services and capacity markets must be adequate for those resources. That adequacy requires a capacity market. The capacity market plays the essential role of equilibrating the revenues necessary to incent competitive entry and exit of the resources needed for reliability, with the revenues from the energy market that are directly affected by nonmarket sources.

Price suppression below the competitive level in the capacity market should not be acceptable and is not consistent with a competitive market design. Harmonizing means that the integrity of each paradigm is maintained and respected. Harmonizing permits nonmarket resources to have an unlimited impact on energy markets and energy prices. Harmonizing means designing a capacity market to account for these energy market impacts, clearly limiting the impact of nonmarket revenues on the capacity market and ensuring competitive outcomes in the capacity market and thus in the entire market.

Overview: Section 6, Demand Response

- **Demand Response Activity.** Demand response activity includes economic demand response (economic resources), emergency and pre-emergency demand response (demand resources), synchronized reserves and regulation. Economic demand response participates in the energy market. Emergency and pre-emergency demand response participates in the capacity market and energy market.[141] Demand response resources participate in the synchronized reserve market. Demand response resources participate in the regulation market.

  Total demand response revenue decreased by $103.3 million, 66.1 percent, from $156.4 million in the first three months of 2022 to $53.1 million in the first three months of 2023. Emergency demand response revenue accounted for 97.1 percent of all demand response revenue, economic demand response for 0.6 percent, demand response in the synchronized reserve market for 0.5 percent and demand response in the regulation market for 1.8 percent.

  Total emergency demand response revenue decreased by $101.5 million, 66.3 percent, from $153.0 million in the first three months of 2022 to $51.5 million in the first three months of 2023.[142] This decrease consisted of capacity market revenue.

  Economic demand response revenue decreased by $0.1 million, 22.2 percent, from $0.4 million in the first three months of 2022 to $0.3 million in the first three months of 2023.[143] Demand response revenue in the synchronized reserve market decreased by $1.6 million, 85.7 percent, from $1.9 million in the first three months of 2022 to $0.3 million in the first three months of 2023. Demand response revenue in the regulation market decreased by $0.1 million, 13.3 percent, from $1.0 million in the first three months of 2022 to $0.9 million in the first three months of 2023.

141 Emergency demand response refers to both emergency and pre-emergency demand response. With the implementation of the Capacity Performance design, there is no functional difference between the emergency and pre-emergency demand response resource.
142 The total credits and MWh numbers for demand resources were downloaded as of April 6, 2023 and may change as a result of continued PJM billing updates.
143 Economic credits are synonymous with revenue received for reductions under the economic load response program.

- **Demand Response Energy Payments are Uplift.** Energy payments to emergency and economic demand response resources are uplift. LMP does not cover energy payments although emergency and economic demand response can and does set LMP. Energy payments to emergency demand resources are paid by PJM market participants in proportion to their net purchases in the real-time market. Energy payments to economic demand resources are paid by real-time exports from PJM and real-time loads in each zone for which the load-weighted, average real-time LMP for the hour during which the reduction occurred is greater than or equal to the net benefits test price for that month.[144]
- **Demand Response Market Concentration.** The ownership of economic load response resources was highly concentrated in the first three months of 2022 and the first three months of 2023. The HHI for economic resource reductions increased by 1528 points from 7861 in the first two months of 2022 to 9459 in the first two months of 2023. The ownership of emergency load response resources is highly concentrated. The HHI for emergency load response committed MW was 2070 for the 2021/2022 Delivery Year. In the 2021/2022 Delivery Year, the four largest CSPs owned 85.3 percent of all committed demand response UCAP MW. The HHI for emergency demand response committed MW is 2051 for the 2022/2023 Delivery Year. In the 2022/2023 Delivery Year, the four largest CSPs own 82.8 percent of all committed demand response UCAP MW.
- **Limited Locational Dispatch of Demand Resources.** With full implementation of the Capacity Performance rules in the capacity market in the 2020/2021 Delivery Year, PJM should be able to individually dispatch any capacity performance resource, including demand resources. But PJM cannot dispatch demand resources by node with the current rules because demand resources are not registered to a node. Aggregation rules allow a demand resource that incorporates many small end use customers to span an entire zone, which is inconsistent with nodal dispatch.

144 "PJM Manual 28: Operating Agreement Accounting," § 11.2.2, Rev. 90 (Jan. 25, 2023).

Section 6 Recommendations

- The MMU recommends that PJM report the response of demand capacity resources to dispatch by PJM as the actual change in load rather than simply the difference between the amount of capacity purchased by the customer and the actual metered load. The current approach significantly overstates the response to PJM dispatch. (Priority: High. New recommendation. Status: Not adopted.)
- The MMU recommends, as a preferred alternative to including demand resources as supply in the capacity market, that demand resources be on the demand side of the markets, that customers be able to avoid capacity and energy charges by not using capacity and energy at their discretion, that customer payments be determined only by metered load, and that PJM forecasts immediately incorporate the impacts of demand side behavior. (Priority: High. First reported 2014. Status: Not adopted.)
- The MMU recommends that the option to specify a minimum dispatch price (strike price) for demand resources be eliminated and that participating resources receive the hourly real-time LMP less any generation component of their retail rate. (Priority: Medium. First reported 2010. Status: Not adopted.)
- The MMU recommends that the maximum offer for demand resources be the same as the maximum offer for generation resources. (Priority: Medium. First reported 2013. Status: Not adopted.)
- The MMU recommends that the demand resources be treated as economic resources, responding to economic price signals like other capacity resources. The MMU recommends that demand resources not be treated as emergency resources, not trigger a PJM emergency and not trigger a Performance Assessment Interval. The MMU recommends that demand resources be available for every hour of the year. (Priority: High. First reported 2012. Status: Not adopted.)
- The MMU recommends that the Emergency Program Energy Only option be eliminated because the opportunity to receive the appropriate energy market incentive is already provided in the economic program. (Priority: Low. First reported 2010. Status: Not adopted.)

- The MMU recommends that, if demand resources remain in the capacity market, a daily energy market must offer requirement apply to demand resources, comparable to the rule applicable to generation capacity resources.[145] (Priority: High. First reported 2013. Status: Not adopted.)
- The MMU recommends that demand resources be required to provide their nodal location, comparable to generation resources. (Priority: High. First reported 2011. Status: Not adopted.)
- The MMU recommends that PJM require nodal dispatch of demand resources with no advance notice required or, if nodal location is not required, subzonal dispatch of demand resources with no advance notice required. The MMU recommends that, if PJM continues to use subzones for any purpose, PJM clearly define the role of subzones in the dispatch of demand response. (Priority: High. First reported 2015. Status: Not adopted.)
- The MMU recommends that PJM not remove any defined subzones and maintain a public record of all created and removed subzones. (Priority: Low. First reported 2016. Status: Not adopted.)
- The MMU recommends that PJM eliminate the measurement of compliance across zones within a compliance aggregation area (CAA). The multiple zone approach is less locational than the zonal and subzonal approach and creates larger mismatches between the locational need for the resources and the actual response. (Priority: High. First reported 2015. Status: Not adopted.)
- The MMU recommends that measurement and verification methods for demand resources be modified to reflect compliance more accurately. (Priority: Medium. First reported 2009. Status: Not adopted.)
- The MMU recommends that compliance rules be revised to include submittal of all necessary hourly load data, and that negative values be included when calculating event compliance across hours and registrations. (Priority: Medium. First reported 2012. Status: Not adopted.)
- The MMU recommends that PJM adopt the ISO-NE five-minute metering requirements in order to ensure that operators have the necessary information for reliability and that market payments to demand resources be calculated based on interval meter data at the site of the demand reductions.[146] (Priority: Medium. First reported 2013. Status: Not adopted.)
- The MMU recommends demand response event compliance be calculated on a five minute basis for all capacity performance resources and that the penalty structure reflect five minute compliance. (Priority: Medium. First reported 2013. Status: Partially adopted.)
- The MMU recommends that load management testing be initiated by PJM with limited warning to CSPs in order to more accurately represent the conditions of an emergency event. (Priority: Low. First reported 2012. Status: Not adopted.)
- The MMU recommends that shutdown cost be defined as the cost to curtail load for a given period that does not vary with the measured reduction or, for behind the meter generators, be the start cost defined in Manual 15 for generators. (Priority: Low. First reported 2012. Status: Not adopted.)
- The MMU recommends that the Net Benefits Test be eliminated and that demand response resources be paid LMP less any generation component of the applicable retail rate. (Priority: Low. First reported 2015. Status: Not adopted.)
- The MMU recommends that the tariff rules for demand response clarify that a resource and its CSP, if any, must notify PJM of material changes affecting the capability of the resource to perform as registered and must terminate or modify registrations that are no longer capable of responding to PJM dispatch directives at defined levels because load has been reduced or eliminated, as in the case of bankrupt and/or out of service facilities. (Priority: Medium. First reported 2015. Status: Not adopted.)
- The MMU recommends that there be only one demand response product in the capacity market, with an obligation to respond when called for any hour of the delivery year. (Priority: High. First reported 2011. Status: Partially adopted.[147])

145 See "Complaint and Motion to Consolidate of the Independent Market Monitor for PJM," Docket No. EL14-20-000 (January 27, 2014) at 1.

146 See ISO-NE Tariff, Section III, Market Rule 1, Appendix E1 and Appendix E2, "Demand Response," <http://www.iso-ne.com/regulatory/tariff/sect_3/mr1_append-e.pdf>. (Accessed October 17, 2017) ISO-NE requires that DR have an interval meter with five-minute data reported to the ISO and each behind the meter generator is required to have a separate interval meter. After June 1, 2017, demand response resources in ISO-NE must also be registered at a single node.

147 PJM's Capacity Performance design requires resources to respond when called for any hour of the delivery year, but demand resources still have a limited mandatory compliance window.

- The MMU recommends that the lead times for demand resources be shortened to 30 minutes with a one hour minimum dispatch for all resources. (Priority: Medium. First reported 2013. Status: Partially adopted.)
- The MMU recommends setting the baseline for measuring capacity compliance under winter compliance at the customers' PLC, similar to GLD, to avoid double counting. (Priority: High. First reported 2010. Status: Partially adopted.)
- The MMU recommends the Relative Root Mean Squared Test be required for all demand resources with a CBL. (Priority: Low. First reported 2017. Status: Partially adopted.)
- The MMU recommends that the limits imposed on the pre-emergency and emergency demand response share of the synchronized reserve market be eliminated. (Priority: Medium. First reported 2018. Status: Not adopted.)
- The MMU recommends that 30 minute pre-emergency and emergency demand response be considered to be 30 minute reserves. (Priority: Medium. First reported 2018. Status: Not adopted.)
- The MMU recommends that energy efficiency resources not be included in the capacity market and that PJM should ensure that the impact of EE measures on the load forecast is incorporated immediately rather than with the existing lag. (Priority: Medium. First reported 2018. Status: Partially adopted.)
- The MMU recommends that, if energy efficiency resources remain in the capacity market, PJM codify eligibility requirements to claim the capacity rights to energy efficiency installations in the tariff and that PJM institute a registration system to track claims to capacity rights to energy efficiency installations and document installation periods of energy efficiency installations. (Priority: Medium. First reported 2022. Status: Not adopted.)
- The MMU recommends that demand reductions based entirely on behind the meter generation be capped at the lower of economic maximum or actual generation output. (Priority: High. First reported 2019. Status: Not adopted.)
- The MMU recommends that all demand resources register as Pre-Emergency Load Response and that the Emergency Load Response Program be eliminated. (Priority: High. First reported 2020. Status: Not adopted.)
- The MMU recommends that EDCs not be allowed to participate in markets as DER aggregators in addition to their EDC role. (Priority: High. First reported 2021. Status: Not adopted.)
- The MMU recommends that PJM include a 5.0 MW maximum size cap on DER aggregations. (Priority: Medium. First reported 2021. Status: Not adopted.)
- The MMU recommends that PJM use a nodal approach for DER participation in PJM markets. (Priority: Medium. First reported 2022. Status: Partially adopted.)

Section 6 Conclusion

A fully functional demand side of the electricity market means that end use customers or their designated intermediaries will have the ability to see real-time energy price signals in real time, will have the ability to react to real-time prices in real time and will have the ability to receive the direct benefits or costs of changes in real-time energy use. In addition, customers or their designated intermediaries will have the ability to see current capacity prices, will have the ability to react to capacity prices and will have the ability to receive the direct benefits or costs of changes in the demand for capacity in the same year in which demand for capacity changes. A functional demand side of these markets means that customers will have the ability to make decisions about levels of power consumption based both on how customers value the power and on the actual cost of that power.

In the energy market, if there is to be a demand side program, demand resources should be paid the value of energy, which is LMP less any generation component of the applicable retail rate. There is no reason to have the net benefits test. The necessity for the net benefits test is an illustration of the illogical approach to demand side compensation embodied in paying full LMP to demand resources. The benefit of demand side resources is not that they suppress market prices, but that customers can choose not to consume at the current price of power, that individual customers benefit from their choices and that the choices of all customers are reflected in market prices. If customers face the market price, customers should have the ability to not purchase power and the market impact of that choice does not require a test for appropriateness.

If demand resources are to continue competing directly with generation capacity resources in the PJM Capacity Market, the product must be defined such that it can actually serve as a substitute for generation. This is a prerequisite to a functional market design. Demand resources do not have a must offer requirement into the day-ahead energy market, are able to offer above $1,000 per MWh without providing a fuel cost policy, or any rationale for the offer. PJM automatically, and inappropriately, triggers a PAI when demand resources are dispatched and demand resources do not have telemetry requirements similar to other Capacity Performance resources.

In order to be a substitute for generation, demand resources should be defined in PJM rules as an economic resource, as generation is defined. Demand resources should be required to offer in the day-ahead energy market and should be called when the resources are required and prior to the declaration of an emergency. Demand resources should be available for every hour of the year. The fact that demand resources are only obligated to respond for defined time periods meant that PJM could not fully use demand resources during Winter Storm Elliott (Elliott). The fact that PJM currently defines demand resources as emergency resources and the fact that calling on demand resources triggers a performance assessment interval (PAI) under the Capacity Performance design, both serve as a significant disincentive to calling on demand resources and mean that demand resources are underused. Demand resources should be treated as economic resources like any other capacity resource. Demand resources should be called whenever economic and paid the LMP rather than an inflated strike price up to $1,849 per MWh that is set by the seller.

In order to be a substitute for generation, demand resources should be subject to robust measurement and verification techniques to ensure that transitional DR programs incent the desired behavior. The methods used in PJM programs today are not adequate to determine and quantify deliberate actions taken to reduce consumption.

In order to be a substitute for generation, demand resources should provide a nodal location and should be dispatched nodally to enhance the effectiveness of demand resources and to permit the efficient functioning of the energy market. Both subzonal and multi-zone compliance should be eliminated because they are inconsistent with an efficient nodal market.

In order to be a substitute for generation, compliance by demand resources with PJM dispatch instructions should include both increases and decreases in load. The current method applied by PJM simply ignores increases in load and thus artificially overstates compliance.

In order to be a substitute for generation, Actual Performance of demand resources during a Performance Assessment Event should be determined consistent with that of generation and should not be netted across the Emergency Action Area (EAA). The Capacity Market Seller's Performance Shortfalls for Demand Resources in the EAA are netted to determine a net EAA Performance Shortfall for the Performance Assessment Interval. Any net positive EAA Performance Shortfall is allocated to the Capacity Market Seller's demand resources that under complied within the EAA on a prorata basis based on the under compliance MW, and such seller's demand resources will be assessed a Performance Shortfall for the Performance Assessment Interval. Any net negative EAA Performance Shortfall is allocated to the Market Seller's Demand Resources that over complied within the EAA on a prorata basis based on over compliance MW, and such Market Seller's Demand Resources will be assessed Bonus Performance. Netting of performance of Demand Resources across the EAA is inconsistent with the performance measurement of other Capacity Performance resources.

In order to be a substitute for generation, any demand resource and its Curtailment Service Provider (CSP), should be required to notify PJM of material changes affecting the capability of the resource to perform as registered and to terminate or modify registrations that are no longer capable of responding to PJM dispatch directives at the specified level, such as in the case of bankrupt and out of service facilities. Generation resources are required to inform PJM of any change in availability status, including outages and shutdown status.

As a preferred alternative to being a substitute for generation in the capacity and energy markets, demand response resources should be on the demand side of the capacity market rather than on the supply side. Rather than detailed demand response programs with their attendant complex and difficult to administer rules, customers would be able to avoid capacity and energy charges by not using capacity and energy at their discretion and the level of usage paid for would be defined by metered usage rather than a complex and inaccurate measurement protocol.

The MMU peak shaving proposal at the Summer-Only Demand Response Senior Task Force (SODRSTF) is an example of how to create a demand side product that is on the demand side of the market and not on the supply side.[148] The MMU proposal was based on the BGE load forecasting program and the Pennsylvania Act 129 Utility Program.[149] [150] Under the MMU proposal, participating load would inform PJM prior to an RPM auction of the MW participating, the months and hours of participation and the temperature humidity index (THI) threshold at which load would be reduced. PJM would reduce the load forecast used in the RPM auction based on the designated reductions. Load would agree to curtail demand to at or below a defined FSL, less than the customer PLC, when the THI exceeds a defined level or load exceeds a specified threshold. By relying on metered load and the PLC, load can reduce its demand for capacity and that reduction can be verified without complicated and inaccurate metrics to estimate load reductions. Under PJM's weakened version of the program, performance is be measured under the current economic demand response CBL rules which means relying on load estimates rather than actual metered load.[151] PJM's proposal includes only a THI curtailment trigger and not an overall load curtailment trigger.

The long term appropriate end state for demand resources in the PJM markets should be comparable to the demand side of any market. Customers should use energy as they wish, accounting for market prices in any way they like, and that usage will determine the amount of capacity and energy for which each customer pays. There would be no counterfactual measurement and verification.

Under this approach, customers that wish to avoid capacity payments would reduce their load during expected high load hours, not limited to a small number of peak hours. Capacity costs would be assigned to LSEs and by LSEs to customers, based on actual load on the system during these hours. Customers wishing to avoid high energy prices would reduce their load during high price hours. Customers would pay for what they actually use, as measured by meters, rather than relying on flawed measurement and verification methods. No measurement and verification estimates are required. No promises of future reductions which can only be verified by inaccurate and biased measurement and verification methods are required. To the extent that customers enter into contracts with CSPs or LSEs to manage their payments, measurement and verification can be negotiated as part of a bilateral commercial contract between a customer and its CSP or LSE. But the system would be paid for actual, metered usage, regardless of which contractual party takes that obligation.

This approach provides more flexibility to customers to limit usage at their discretion. There is no requirement to be available year round or every hour of every day. There is no 30 minute notice requirement. There is no requirement to offer energy into the day-ahead market. All decisions about interrupting are up to the customers only and they may enter into bilateral commercial arrangements with CSPs at their sole discretion. Customers would pay for capacity and energy depending solely on metered load.

148 See the MMU package within the *SODRSTF Matrix*, <http://www.pjm.com/-/media/committees-groups/task-forces/sodrstf/20180802/20180802-item-04-sodrstf-matrix.ashx>.

149 *Advance signals that can be used to foresee demand response days*, BGE, <https://www.pjm.com/-/media/committees-groups/task-forces/sodrstf/20180309/20180309-item-05-bge-load-curtailment-programs.ashx> (Accessed April 28, 2022).

150 *Pennsylvania ACT 129 Utility Program*, CPower, <https://www.pjm.com/-/media/committees-groups/task-forces/sodrstf/20180413/20180413-item-03-pa-act-129-program.ashx> (Accessed April 28, 2022).

151 The PJM proposal from the SODRSTF weakened the proposal but was approved at the October 25, 2018 Members Committee meeting and PJM filed Tariff changes on December 7, 2018. See "Peak Shaving Adjustment Proposal," Docket No. ER19-511-000 (December 7, 2018).

A transition to this end state should be defined in order to ensure that appropriate levels of demand side response are incorporated in PJM's load forecasts and thus in the demand curve in the capacity market. That transition should be defined by the PRD rules, modified as proposed by the MMU.

This approach would work under the CP design in the capacity market. This approach is entirely consistent with the Supreme Court decision in *EPSA* as it does not depend on whether FERC has jurisdiction over the demand side.[152] This approach will allow FERC to more fully realize its overriding policy objective to create competitive and efficient wholesale energy markets. The decision of the Supreme Court addressed jurisdictional issues and did not address the merits of FERC's approach. The Supreme Court's decision has removed the uncertainty surrounding the jurisdictional issues and created the opportunity for FERC to revisit its approach to demand side.

Any discussion of demand resource performance during a PAI must recognize the significant problems with the definition of performance for demand resources. As defined by PJM rules, performance, contrary to intuition, does not mean actually reducing load in response to a PJM request for demand resources. Performance means only that, on a net portfolio basis, the amount of capacity paid for in the capacity market (PLC) minus actual metered load is equal to the amount of demand side capacity sold in the capacity market (ICAP). If a demand resource location was already at a reduced load level when PJM called a PAI, the demand resource would be deemed to have performed if the PLC less the metered load level was equal to the ICAP sold in the capacity market. The standard reporting of demand side response is therefore misleading because it includes loads that were already lower for any reason as a response.

152 577 U.S. 260 (2016).

Overview: Section 7, Net Revenue

Net Revenue

- Energy market net revenues are significantly affected by energy prices and fuel prices. Energy prices and fuel prices were significantly lower in the first three months of 2023 than in the first three months of 2022. The net effects were that in the first three months of 2023, average energy market net revenues decreased by 57 percent for a new combustion turbine (CT), 42 percent for a new combined cycle (CC), 89 percent for a new coal plant (CP), 41 percent for a new nuclear plant, 90 percent for a new diesel (DS), 34 percent for a new onshore wind installation, 50 percent for a new offshore wind installation and 49 percent for a new solar installation.
- The price of natural gas, Northern Appalachian coal and PRB coal decreased in the first three months of 2023. The marginal costs of a new CC and CT were less than the marginal cost of a new CP in the first three months of 2023.
- In the first three months of 2023, spark spreads increased in BGE, COMED, and Western Hub and dark spreads decreased. The volatility of both spark spreads and dark spreads decreased in BGE and PSEG compared to the first three months of 2022.
- All existing PJM nuclear plants are expected to cover their avoidable costs from energy and capacity market revenues in 2023, 2024, and 2025, without subsidies, with the exception of Davis Besse, a single unit nuclear plant, in 2023.

Section 7 Recommendations

- The MMU recommends that the net revenue calculation used by PJM to calculate the net Cost of New Entry (CONE) and net ACR be based on a forward looking calculation of expected energy and ancillary services net revenues using forward prices for energy and fuel. (Priority: Medium. First reported 2019. Status: Not adopted.)

Section 7 Conclusion

Wholesale electric power markets are affected by externally imposed reliability requirements. A regulatory authority external to the market makes a determination as to the acceptable level of reliability which is enforced through a requirement to maintain a target level of installed or unforced capacity. The requirement to maintain a target level of installed capacity can be enforced via a variety of mechanisms, including government construction of generation, full-requirement contracts with developers to construct and operate generation, state utility commission mandates to construct capacity, or capacity markets of various types. Regardless of the enforcement mechanism, the exogenous requirement to construct capacity in excess of what is constructed in response to energy market signals has an impact on energy markets. The reliability requirement results in maintaining a level of capacity in excess of the level that would result from the operation of an energy market alone. The result of that additional capacity is to reduce the level and volatility of energy market prices and to reduce the duration of high energy market prices. This, in turn, reduces net revenue to generation owners which reduces the incentive to invest. The exact level of both aggregate and locational excess capacity is a function of the calculation methods used by RTOs and ISOs. A basic purpose of the capacity market is allow all cleared capacity resources the opportunity to cover their net avoidable costs on an annual basis to ensure the economic sustainability of the reliable energy market.

Overview: Section 8, Environmental and Renewables

Federal Environmental Regulation

- **MATS.** The U.S. Environmental Protection Agency's (EPA) Mercury and Air Toxics Standards rule (MATS) applies the Clean Air Act (CAA) maximum achievable control technology (MACT) requirement to new or modified sources of emissions of mercury and arsenic, acid gas, nickel, selenium and cyanide.[153] On February 13, 2023, the EPA issued a final rule reaffirming that it remains appropriate and necessary to regulate hazardous air pollutants (HAP), including mercury, from power plants after considering cost.[154] This action revokes a 2020 finding that it was not appropriate and necessary to regulate coal and oil fired power plants under CAA § 112, and would restore the basis for the MATS rule.
- **Air Quality Standards (NO_X and SO_2 Emissions).** The CAA requires each state to attain and maintain compliance with fine particulate matter (PM) and ozone national ambient air quality standards (NAAQS). The CAA also requires that each state prohibit emissions that significantly interfere with the ability of another state to meet NAAQS.[155] On March 15, 2021, the EPA finalized decreases to allowable emissions under the Cross-State Air Pollution Rule (CSAPR) and the 2008 ozone NAAQS for 10 PJM states.[156] On February 28, 2022, the EPA proposed a Federal Implementation Plan (FIP), to be known as the "Transport Rule," for 26 states that addresses the contribution of those states to problems in other states in attaining and maintaining the 2015 Ozone NAAQS.[157] The proposed FIP requirements would establish ozone season NO_X emissions budgets for electric generating units in the PJM states, excluding North Carolina and the District of Columbia. On January 6, 2023, the EPA proposed to lower the primary annual $PM_{2.5}$ standard to 9.0 to 10.0 µg/m^3 from 12.0 µg/m^3.[158]
- **NSR.** On August 1, 2019, the EPA proposed to reform the New Source Review (NSR) permitting program.[159] NSR requires new projects and existing projects receiving major overhauls that significantly increase emissions to obtain permits. Recent EPA proposals would reduce the number of projects that require permits.
- **RICE.** Stationary reciprocating internal combustion engines (RICE) are electrical generation facilities like diesel engines typically used for backup, emergency or supplemental power. RICE must be tested annually.[160] RICE do not have to meet the same emissions standards if they are emergency

153 *National Emission Standards for Hazardous Air Pollutants From Coal and Oil-Fired Electric Utility Steam Generating Units and Standards of Performance for Fossil Fuel Fired Electric Utility, Industrial-Commercial-Institutional, and Small Industrial-Commercial-Institutional Steam Generating Units*, EPA Docket No. EPA-HQ-OAR-2009-0234, 77 Fed. Reg. 9304 (Feb. 16, 2012).

154 See *Natioal Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units—Revocation of the 2020 Reconsideration, and Affirmation of the Appropriate and Necessary Supplemental Finding*, Notice of Proposed Rulemaking, EPA-HQ-OAR-2018-0794, 87 Fed. Reg. 7624.

155 CAA § 110(a)(2)(D)(i)(I).

156 *Revised Cross-State Air Pollution Rule Update for the 2008 Ozone NAAQS*, Docket No. EPA-HQ-OAR-2020-0272; FRL-10013-42- OAR, 85 Fed. Reg. 23054 (Apr. 30, 2021).

157 See *Federal Implementation Plan Addressing Regional Ozone Transport for the 2015 Ozone National Ambient Air Quality Standard*, Docket No. EPA-HQ-OAR-2021-0668; FRL 8670-01-OAR, 87 Fed. Reg. 20036 (April 6, 2022).

158 *See Reconsideration of the National Ambient Air Quality Standards for Particulate Matter.* Proposed Rule, Docket No. EPA-HQ-OAR-2015-0072; FRL-8635-01- OAR, 88 Fed. Reg. 5558 (January 27, 2023).

159 *Prevention of Significant Deterioration (PSD) and Nonattainment New Source Review (NNSR): Project Emissions Accounting*, EPA Docket No. EPA-HQ-OAR-2018-0048; FRL-9997-95-OAR, 84 Fed. Reg. 39244 (Aug. 9, 2019).

160 See 40 CFR § 63.6640(f).

stationary RICE. Environmental regulations allow emergency stationary RICE participating in demand response programs to operate for up to 100 hours per calendar year when providing emergency demand response when there is a PJM declared NERC Energy Emergency Alert Level 2 or there are five percent voltage/frequency deviations.

PJM does not prevent emergency stationary RICE that cannot meet its capacity market obligations as a result of EPA emissions standards from participating in PJM markets as DR. Some emergency stationary RICE that cannot meet its capacity market obligations as a result of emissions standards are now included in DR portfolios. Emergency stationary RICE should be prohibited from participation as DR either when registered individually or as part of a portfolio if it cannot meet its capacity market obligations as a result of emissions standards.

- **Greenhouse Gas Emissions.** On June 30, 2022, the Supreme Court held that Section 111(d) of the CAA did not provide authority under the major questions doctrine to regulate carbon emissions in the manner proposed.[161] Both the EPA's Affordable Clean Energy (ACE) rule and the Clean Power Plan (CPP), which were promulgated under Section 111(d) of the CAA, are expected to be vacated on remand.
- **Cooling Water Intakes.** An EPA rule implementing Section 316(b) of the Clean Water Act (CWA) requires that cooling water intake structures reflect the best technology available for minimizing adverse environmental impacts.[162]
- **Waters of the United States.** On December 30, 2022, the EPA and the Army Corps of Engineers announced a final rule revising the definition of WOTUS.[163] The rule will become effective on March 20, 2023.
- **Effluents.** Under the CWA, the EPA regulates (National Pollutant Discharge Elimination System (NPDES)) discharges from and intakes to power plants, including water cooling systems at steam electric power generating stations. The EPA has recently been strengthening certain discharge limits applicable to steam generating units, and some plant owners have already indicated an intent to close certain generating units as a result.
- **Coal Ash.** The EPA administers the Resource Conservation and Recovery Act (RCRA), which governs the disposal of solid and hazardous waste.[164] The EPA has adopted significant changes to the implementing regulations that will require closing noncompliant impoundments, and, as a result, the host power plant. The EPA is implementing a process for extensions to as late as October 17, 2028. The EPA is reviewing applications received from PJM plant owners for extensions of the deadline for compliance with the revised Coal Combustion Residuals Rule.

State Environmental Regulation

- **Regional Greenhouse Gas Initiative (RGGI).** The Regional Greenhouse Gas Initiative (RGGI) is a CO_2 emissions cap and trade agreement among Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New Jersey, New York, Rhode Island, Vermont and Virginia that applies to power generation facilities. New Jersey rejoined on January 1, 2020.[165] Virginia joined RGGI on January 1, 2021. Pennsylvania took action to join RGGI on April 23, 2022, but such action has been enjoined by court order on appeal.[166] [167] A decision on the merits of the appeal is pending at the Supreme Court of Pennsylvania. The auction price in the March 8, 2023 RGGI auction was $12.50 per short ton, or $13.78 per metric tonne.
- **Illinois Climate and Equitable Jobs Act (CEJA).** On September 16, 2021, the Climate and Equitable Jobs Act (CEJA) became effective. CEJA created an expanded nuclear subsidy program. CEJA mandates that all fossil fuel plants close by 2045. CEJA established emissions caps for investor owned, gas-fired units with three years of operating history, effective October 1,

161 *West Virginia v. EPA*, No. 20–1530 (S. Ct. of the U.S.).
162 See EPA, *National Pollutant Discharge Elimination System—Final Regulations to Establish Requirements for Cooling Water Intake Structures at Existing Facilities and Amend Requirements at Phase I Facilities*, EPA-HQ-OW-2008-0667, 79 Fed. Reg. 48300 (Aug. 15, 2014).
163 *See Revised Definition of "Waters of the United States,"* Final Rule, Docket No. [EPA–HQ–OW–2021–0602; FRL–6027.4–01–OW, 88 Fed. Reg. 3004 (January 18, 2023)
164 42 U.S.C. §§ 6901 *et seq.*
165 "Statement on New Jersey Greenhouse Gas Rule," RGGI Inc., (June 17, 2019) <https://www.rggi.org/sites/default/files/Uploads/Press-Releases/2019_06_17_NJ_Announcement_Release.pdf>.
166 CO2 Budget Trading Program, 52 Pa.B. 2471 (April 23, 2022), codified 25 Pa. Code Ch. 145; *see also* Executive Order–2019-07. Commonwealth Leadership in Addressing Climate Change through Electric Sector Emissions Reductions, Tom Wolf, Governor, October 3, 2019, <https://www.governor.pa.gov/newsroom/executive-order-2019-07-commonwealth-leadership-in-addressing-climate-change-through-electric-sector-emissions-reductions/> .
167 See *Ramez Ziadeh, et al. v. Pennsylvania Legislative Reference Bureau*, Memorandum Opinion, Commonwealth Court of Pennsylvania Case No. No. 41 M.D. 2022 (July 8, 2022); *Ramez Ziadeh, et al. v. Pennsylvania Legislative Reference* Bureau, Order Granting Application to Vacate, Commonwealth Court of Pennsylvania Case No. No. 41 M.D. 2022 (July 25, 2022).

2021, on a rolling 12 month basis. More than 10,000 MW of capacity are currently affected.

- **Carbon Price.** If the price of carbon were $50.00 per metric tonne, short run marginal costs would increase by $24.45 per MWh or 70.9 percent for a new combustion turbine (CT) unit, $16.85 per MWh or 74.8 percent for a new combined cycle (CC) unit and $43.09 per MWh or 82.4 percent for a new coal plant (CP) for the first three months of 2023.

State Renewable Portfolio Standards

- **RPS.** In PJM, ten of 14 jurisdictions have enacted legislation requiring that a defined percentage of retail suppliers' load be served by renewable resources, for which definitions vary. These are typically known as renewable portfolio standards, or RPS. As of March 31, 2023, Delaware, Illinois, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Virginia and Washington, DC have renewable portfolio standards. Indiana has a voluntary renewable portfolio standard. Kentucky, Tennessee and West Virginia do not have renewable portfolio standards.
- **RPS Cost.** The cost of complying with RPS, as reported by the states, is $7.2 billion over the seven year period from 2014 through 2020, an average annual RPS compliance cost of $1.0 billion. The compliance cost for 2020, the most recent year with almost complete data, was $1.5 billion.[168]

Emissions Controls in PJM Markets

- **Regulations.** Environmental regulations affect decisions about emission control investments in existing units, investment in new units and decisions to retire units. As a result of environmental regulations and agreements to limit emissions, many PJM units burning fossil fuels have installed emission control technology.
- **Emissions Controls.** In PJM, as of March 31, 2023, 96.0 percent of coal steam MW had some type of flue-gas desulfurization (FGD) technology to reduce SO_2 emissions, 99.8 percent of coal steam MW had some type of particulate matter (PM) control, and 99.8 percent of coal steam MW had NO_x emission control technology. All coal steam units in PJM are compliant with the state and federal emissions limits established by MATS.

Renewable Generation

- **Renewable Generation.** Wind and solar generation was 5.8 percent of total generation in PJM for the first three months of 2023. RPS Tier I generation was 7.4 percent of total generation in PJM and RPS Tier II generation was 1.9 percent of total generation in PJM for the first three months of 2023. Only Tier I generation is defined to be renewable but Tier 1 includes some carbon emitting generation.
- PJM states with RPS rely heavily on imports and generation from behind the meter resources for RPS compliance. In the first three months of 2023, Tier I generation in PJM met only 58.4 percent of the Tier I RPS requirements.

Section 8 Recommendations

- The MMU recommends that renewable energy credit markets based on state renewable portfolio standards be brought into PJM markets as they are an increasingly important component of the wholesale energy market. The MMU recommends that there be a single PJM operated forward market for RECs, for a single product based on a common set of state definitions of renewable technologies, with a single clearing price, trued up to real time delivery. (Priority: High. First reported 2010. Status: Not adopted.)
- The MMU recommends that PJM provide a full analysis of the impact of carbon pricing on PJM generating units and carbon pricing revenues to the PJM states in order to permit the states to consider a potential agreement on the development of a multistate framework for carbon pricing and the distribution of carbon revenues. (Priority: High. First reported 2018. Status: Not adopted.)

168 The 2020 compliance cost value for PJM states does not include Illinois, Michigan or North Carolina. Based on past data these states generally account for 3.0 percent of the total RPS compliance cost of PJM states.

- The MMU recommends that jurisdictions with a renewable portfolio standard make the price and quantity data on supply and demand more transparent. (Priority: Low. First reported 2018. Status: Not adopted.)
- The MMU recommends that the Commission reconsider its disclaimer of jurisdiction over RECs markets because, given market changes since that decision, it is clear that RECs materially affect jurisdictional rates. (Priority: Low. First reported 2018. Status: Not adopted.)
- The MMU recommends that load and generation located at separate nodes be treated as separate resources in order to ensure that load and generation face consistent incentives throughout the markets. (Priority: High. First reported 2019. Status: Not adopted.)
- The MMU recommends that emergency stationary RICE be prohibited from participation as DR either when registered individually or as part of a portfolio if it cannot meet the capacity market requirements to be DR as a result of emissions standards that impose environmental run hour limitations. (Priority: Medium. First reported 2019. Status: Not adopted.)

Section 8 Conclusion

Environmental requirements and renewable energy mandates at both the federal and state levels have a significant impact on the cost of energy and capacity in PJM markets.

Environmental requirements and initiatives at both the federal and state levels, and state renewable energy mandates and associated subsidies have resulted in the construction of substantial amounts of renewable capacity in the PJM footprint, especially wind and solar resources, and the retirement of emitting resources. Renewable energy credit (REC) markets created by state programs, and federal tax credits have significant impacts on PJM wholesale markets. But state renewables programs in PJM are not coordinated with one another, are generally not consistent with the PJM market design or PJM prices, have widely differing objectives, including supporting some emitting resources, have widely differing implied prices of carbon and are not transparent on pricing and quantities. The effectiveness of state renewables programs would be enhanced if they were coordinated with one another and with PJM markets, and if they increased transparency. States could evaluate the impacts of a range of carbon prices if PJM would provide a full analysis of the impact of carbon pricing on PJM generating units and carbon pricing revenues to the PJM states in order to permit the states to consider a potential agreement on the development of a multistate framework for carbon pricing and the distribution of carbon revenues. A single carbon price across PJM, established by the states, would be the most efficient way to reduce carbon output, if that is the goal.

But in the absence of a PJM market carbon price, a single PJM market for RECs would contribute significantly to market efficiency and to the procurement of renewable resources in a least cost manner. Ideally, there would be a single PJM operated forward market for RECs, for a single product based on a common set of state definitions of renewable technologies, with a single clearing price, trued up to real-time delivery. States would continue to have the option to create separate RECs for additional products that did not fit the product definition, e.g. waste coal, trash incinerators, or black liquor.

RECs are an important mechanism used by PJM states to implement environmental policy. RECs clearly affect prices in the PJM wholesale power market. Some resources are not economic except for the ability to purchase or sell RECs. RECs provide out of market payments to qualifying renewable resources, primarily wind and solar. The credits provide an incentive to make negative energy offers and more generally provide an incentive to enter the market, to remain in the market and to operate whenever possible. These subsidies affect the offer behavior and the operational behavior of these resources in PJM markets and in some cases the existence of these resources and thus the market prices and the mix of clearing resources.

RECs markets are, as an economic fact, integrated with PJM markets including energy and capacity markets, but are not formally recognized as part of PJM markets. It would be preferable to have a single, transparent market for RECs operated by the PJM RTO on behalf of the states that would meet the standards and requirements of all states in the PJM footprint. This would provide better information for market participants about supply and demand and prices and contribute to a more efficient and competitive market and to better price formation. This could also facilitate entry by qualifying renewable resources by reducing the risks associated with lack of transparent market data.

Existing REC markets are not consistently or adequately transparent. Data on REC prices, clearing quantities and markets are not publicly available for all PJM states. The economic logic of RPS programs and the associated REC and SREC prices is not always clear. The price of carbon implied by REC prices ranges from $16.69 per tonne in Ohio to $35.62 per tonne in New Jersey. The price of carbon implied by SREC prices ranges from $81.62 per tonne in Pennsylvania to $842.51 per tonne in Washington, DC. The effective prices for carbon compare to the RGGI clearing price in March 2023 of $13.78 per tonne and to the social cost of carbon which is estimated in the range of $50 per tonne.[169] The impact on the cost of generation from a new combined cycle unit of a $50 per tonne carbon price would be $16.85 per MWh.[170] The impact of an $800 per tonne carbon price would be $269.59 per MWh. This wide range of implied carbon prices is not consistent with an efficient, competitive, least cost approach to the reduction of carbon emissions.

In addition, even the explicit environmental goals of RPS programs are not clear. While RPS is frequently considered to target carbon emissions, Tier 1 resources include some carbon emitting generation and Tier 2 resources include additional carbon emitting generation.

PJM markets provide a flexible mechanism for incorporating the costs of environmental controls and meeting environmental requirements in a cost effective manner. Costs for environmental controls are part of offers for capacity resources in the PJM Capacity Market. The costs of emissions credits are included in energy offers. PJM markets also provide a flexible mechanism that incorporates renewable resources and the impacts of renewable energy credit markets, and ensures that renewable resources have access to a broad market. PJM markets provide efficient price signals that permit valuation of resources with very different characteristics when they provide the same product.

If the states chose this policy option, PJM markets could also provide a flexible mechanism to limit carbon output, for example by incorporating a consistent carbon price in unit offers which would be reflected in PJM's economic dispatch. If there is a social decision to limit carbon output, a consistent carbon price would be the most efficient way to implement that decision. The states in PJM could agree, if they decided it was in their interests, with the appropriate information, on a carbon price and on how to allocate the revenues from a carbon price that would make all states better off. A mechanism like RGGI leaves all decision making with the states. The carbon price would not be FERC jurisdictional or subject to PJM decisions. The MMU continues to recommend that PJM provide a full analysis of the impact of carbon pricing on PJM generating units and carbon pricing revenues to the PJM states in order to permit the states to consider a potential agreement on the development of a multistate framework for carbon pricing and the distribution of carbon revenues. The results of the analysis would include the impact on the dispatch of every unit, the impact on energy prices and the carbon pricing revenues that would flow to each state.

For example, states receiving high levels of revenue could shift revenue to states disproportionately hurt by a carbon price if they believed that all states would be better off as a result. A carbon price would also be an alternative to specific subsidies to individual nuclear power plants and to the current wide range of implied carbon prices embedded in RPS programs and instead provide a market signal to which any resource could respond. The imposition of specific and prescriptive environmental dispatch rules would, in contrast, pose a threat to economic dispatch and efficient markets and create very difficult market power monitoring and mitigation issues. The provision of subsidies to individual units creates a discriminatory regime that is not consistent with competition. The use of inconsistent implied carbon prices by state is also inconsistent with an efficient market and inconsistent with the least cost approach to meeting state environmental goals.

169 "Technical Update of the Social Cost of Carbon for Regulatory Impact Analysis – Under Executive Order 12899," Interagency Working Group on the Social Cost of Greenhouse Gases, United States Government, (Aug. 2016), <https://19january2017snapshot.epa.gov/sites/production/files/2016-12/documents/sc_co2_tsd_august_2016.pdf>.

170 The cost impact calculation assumes a heat rate of 6.296 MMBtu per MWh and a carbon emissions rate of 0.05290995 tonne per MMBtu. The $800 per tonne carbon price represents the approximate upper end of the carbon prices implied by the 2022 REC and SREC prices in the PJM jurisdictions with RPS. Additional cost impacts are provided in Table 8-7.

The annual average cost of complying with RPS over the seven year period from 2014 through 2020 for the nine jurisdictions that had RPS was $1.0 billion, or a total of $7.2 billion over seven years. The RPS compliance cost for 2020, the most recent year for which there is almost complete data, was $1.5 billion.[171] RPS costs are payments by customers to the sellers of qualifying resources. The revenues from carbon pricing flow to the states.

If all the PJM states participated in a regional carbon market, the estimated revenue returned to the states/customers from selling carbon allowances would be approximately $3.5 billion per year if the carbon price were $12.50 per short ton and emissions levels were five percent below 2021 emission levels. If all the PJM states participated in a regional carbon market, the estimated revenue returned to the states/customers from selling carbon allowances would be approximately $14.1 billion if the carbon price were $50 per short ton and emission levels were five percent below 2021 levels. If only the current RPS states participated in a regional carbon market, the estimated revenue returned to the states/customers from selling carbon allowances at $12.50 per short ton would be about $2.3 billion. The costs of a carbon price are the impact on energy market prices, net of the revenue returned to states/customers.

Overview: Section 9, Interchange Transactions

Interchange Transaction Activity

- **Aggregate Imports and Exports in the Real-Time Energy Market.** In the first three months of 2023, PJM was a monthly net exporter of energy in the real-time energy market in all months.[172] In the first three months of 2023, the real-time net interchange was -8,339.9 GWh. The real-time net interchange in the first three months of 2022 was -9,458.6 GWh.
- **Aggregate Imports and Exports in the Day-Ahead Energy Market.** In the first three months of 2023, PJM was a monthly net exporter of energy in the day-ahead energy market in all months. In the first three months of 2023, the total day-ahead net interchange was -8,385.4 GWh. The day-ahead net interchange in the first three months of 2022 was -8,737.1 GWh.
- **Aggregate Imports and Exports in the Day-Ahead and the Real-Time Energy Market.** In the first three months of 2023, gross imports in the day-ahead energy market were 111.7 percent of gross imports in the real-time energy market (83.7 percent in the first three months of 2022). In the first three months of 2023, gross exports in the day-ahead energy market were 104.4 percent of the gross exports in the real-time energy market (89.6 percent in the first three months of 2022).
- **Interface Imports and Exports in the Real-Time Energy Market.** In the first three months of 2023, there were net scheduled exports at 14 of PJM's 19 interfaces in the real-time energy market.
- **Interface Pricing Point Imports and Exports in the Real-Time Energy Market.** In the first three months of 2023, there were net scheduled exports at five of PJM's seven interface pricing points eligible for real-time transactions in the real-time energy market.
- **Interface Imports and Exports in the Day-Ahead Energy Market.** In the first three months of 2023, there were net scheduled exports at 12 of PJM's 19 interfaces in the day-ahead energy market.
- **Interface Pricing Point Imports and Exports in the Day-Ahead Energy Market.** In the first three months of 2023, there were net scheduled exports at six of PJM's seven interface pricing points eligible for day-ahead transactions in the day-ahead energy market.
- **Up To Congestion Interface Pricing Point Imports and Exports in the Day-Ahead Energy Market.** In the first three months of 2023, up to congestion transactions were net exports at five of PJM's seven interface pricing points eligible for day-ahead transactions in the day-ahead energy market.
- **Inadvertent Interchange.** In the first three months of 2023, net scheduled interchange was -8,339.9 GWh and net actual interchange was -8,281.9 GWh, a difference of 58.0 GWh. In the first three months of 2022, the difference was 24.5 GWh. This difference is inadvertent interchange.

171 The 2020 compliance cost value for PJM states does not include Illinois, Michigan or North Carolina. Based on past data these states generally account for 3.0 percent of the total RPS compliance cost of PJM states.
172 Calculated values shown in Section 9, "Interchange Transactions," are based on unrounded, underlying data and may differ from calculations based on the rounded values in the tables.

- **Loop Flows.** In the first three months of 2023, the Northern Indiana Public Service (NIPS) Interface had the largest loop flows of any interface with -0.2 GWh of net scheduled interchange and -3,276.9 GWh of net actual interchange, a difference of 3,276.8 GWh. In the first three months of 2023, the MISO interface pricing point had the largest loop flows of any interface pricing point with 6,080.0 GWh of net scheduled interchange and 8,021.8 GWh of net actual interchange, a difference of 1,941.9 GWh.
- **Winter Storm Elliott.** Winter Storm Elliott (Elliott) had a significant impact on PJM from December 23, 2022, through December 26, 2022, primarily as a result of low temperatures. Elliott affected interchange transaction volumes, resulted in large volumes of transaction curtailments and required the sale of emergency power to neighboring balancing authorities.

Interactions with Bordering Areas

PJM Interface Pricing with Organized Markets

- **PJM and MISO Interface Prices.** In the first three months of 2023, the direction of the hourly flow was consistent with the real-time hourly price differences between the PJM/MISO Interface and the MISO/PJM Interface in 59.8 percent of the hours.
- **PJM and New York ISO Interface Prices.** In the first three months of 2023, the direction of the hourly flow was consistent with the real-time hourly price differences between the PJM/NYIS Interface and the NYISO/PJM proxy bus in 57.9 percent of the hours.
- **Neptune Underwater Transmission Line to Long Island, New York.** In the first three months of 2023, the hourly flow (PJM to NYISO) was consistent with the real-time hourly price differences between the PJM Neptune Interface and the NYISO Neptune bus in 87.6 percent of the hours.
- **Linden Variable Frequency Transformer (VFT) Facility.** In the first three months of 2023, the hourly flow (PJM to NYISO) was consistent with the real-time hourly price differences between the PJM Linden Interface and the NYISO Linden bus in 82.9 percent of the hours.
- **Hudson DC Line.** In the first three months of 2023, the hourly flow (PJM to NYISO) was consistent with the real-time hourly price differences between the PJM Hudson Interface and the NYISO Hudson bus in 75.2 percent of the hours.

Interchange Transaction Issues

- **PJM Transmission Loading Relief Procedures (TLRs).** PJM issued zero TLRs of level 3a or higher in the first three months of 2023, and zero such TLRs in the first three months of 2022.
- **Up To Congestion.** The average number of up to congestion bids submitted in the day-ahead energy market increased by 132.8 percent, from 33,055 bids per day in the first three months of 2022 to 76,959 bids per day in the first three months of 2023. The average cleared volume of up to congestion bids submitted in the day-ahead energy market increased by 135.2 percent, from 247,428 MWh per day in the first three months of 2022, to 582,009 MWh per day in the first three months of 2023.

Section 9 Recommendations

- The MMU recommends that PJM implement rules to prevent sham scheduling. The MMU recommends that PJM apply after the fact market settlement adjustments to identified sham scheduling segments to ensure that market participants cannot benefit from sham scheduling. (Priority: High. First reported 2012. Status: Not adopted.)
- The MMU recommends that PJM implement a validation method for submitted transactions that would prohibit market participants from breaking transactions into smaller segments to defeat the interface pricing rule by concealing the true source or sink of the transaction. (Priority: Medium. First reported 2013. Status: Not adopted.)
- The MMU recommends that PJM implement a validation method for submitted transactions that would require market participants to submit transactions on paths that reflect the expected actual power flow in order to reduce unscheduled loop flows. (Priority: Medium. First reported 2013. Status: Not adopted.)
- The MMU recommends that transactions sourcing in the Western Interconnection be priced at either the MISO interface pricing point or

the SOUTH interface pricing point based on the locational price impact of flows between the DC tie line point of connection with the Eastern Interconnection and PJM. (Priority: High. First reported 2020. Status: Not adopted.)

- The MMU recommends that PJM eliminate the IMO interface pricing point, and assign the transactions that originate or sink in the IESO balancing authority to the MISO interface pricing point. (Priority: Medium. First reported 2013. Status: Not adopted.)
- The MMU recommends that PJM monitor, and adjust as necessary, the weights applied to the components of the interfaces to ensure that the interface prices reflect ongoing changes in system conditions. The MMU also recommends that PJM review the mappings of external balancing authorities to individual interface pricing points to reflect changes to the impact of the external power source on PJM tie lines as a result of system topology changes. The MMU recommends that this review occur at least annually. (Priority: Low. First reported 2009. Status: Not adopted.)
- The MMU recommends that, in order to permit a complete analysis of loop flow, FERC and NERC ensure that the identified data are made available to market monitors as well as other industry entities determined appropriate by FERC. (Priority: Medium. First reported 2003. Status: Not adopted.)
- The MMU recommends that PJM explore an interchange optimization solution with its neighboring balancing authorities that would remove the need for market participants to schedule physical transactions across seams. Such a solution would include an optimized, but limited, joint dispatch approach that uses supply curves and treats seams between balancing authorities as constraints, similar to other constraints within an LMP market. (Priority: Medium. First reported 2014. Status: Not adopted.)
- The MMU recommends that PJM permit unlimited spot market imports as well as unlimited nonfirm point to point willing to pay congestion imports and exports at all PJM interfaces in order to improve the efficiency of the market. (Priority: Medium. First reported 2012. Status: Not adopted.)
- The MMU recommends that the emergency interchange cap be replaced with a market based solution. (Priority: Low. First reported 2015. Status: Not adopted.)
- The MMU recommends that the submission deadline for real-time dispatchable transactions be modified from 1800 on the day prior, to three hours prior to the requested start time, and that the minimum duration be modified from one hour to 15 minutes. These changes would give PJM a more flexible product that could be used to meet load in the most economic manner. (Priority: Medium. First reported 2014. Status: Partially adopted, 2015.)
- The MMU recommends modifications to the FFE calculation to ensure that FFE calculations reflect the current capability of the transmission system as it evolves. The MMU recommends that the Commission set a deadline for PJM and MISO to resolve the FFE freeze date and related issues. (Priority: Medium. First reported 2019. Status: Not adopted.)
- The MMU recommends clear, explicit and detailed rules that define the conditions under which PJM will and will not recall energy from PJM capacity resources and prohibit new energy exports from PJM capacity resources. The MMU recommends that those rules define the conditions under which PJM will purchase emergency energy while at the same time not recalling energy exports from PJM capacity resources. The MMU recommends clear rules governing when PJM may recall capacity backed exports. (Priority: Medium. First reported 2010. Status: Partially adopted.)

Section 9 Conclusion

Transactions between PJM and multiple balancing authorities in the Eastern Interconnection are part of a single energy market. While some of these balancing authorities are termed market areas and some are termed nonmarket areas, all electricity transactions are part of a single energy market. Nonetheless, there are significant differences between market and nonmarket areas. Market areas, like PJM, include essential features of an energy market including locational marginal pricing, financial congestion offsets (FTRs and ARRs in PJM) and transparent, least cost, security constrained economic dispatch for all available generation. Nonmarket areas do not include these features.

Pricing in the market areas is transparent and pricing in the nonmarket areas is not transparent.

The MMU's recommendations related to transactions with external balancing authorities all share the goal of improving the economic efficiency of interchange transactions. The standard of comparison is an LMP market. In an LMP market, redispatch based on LMP and competitive generator offers results in an efficient dispatch and efficient prices. The goal of designing interface transaction rules should be to match the outcomes that would exist in an LMP market across the interfaces.

It is not appropriate to have special pricing agreements between PJM and any external entity. The same market pricing should apply to all transactions. External entities wishing to receive the benefits of the PJM LMP market should join PJM.

In 2020, PJM terminated a number of interface pricing points, consistent with longstanding MMU recommendations. Following the termination of the Northwest pricing point on October 1, 2020, PJM failed to correctly map the pricing points to transactions that had been mapped to the Northwest pricing point to pricing points that are consistent with electrical impacts on the PJM system. On October 1, 2022, PJM terminated the Southeast and Southwest interface pricing points. The MMU recommends that transactions sourcing in the Western Interconnection be priced at either the MISO interface pricing point or the SOUTH interface pricing point based on the electrical impact of flows between the DC tie line point of connection with the Eastern Interconnection and PJM. The MMU continues to recommend the termination of the Ontario interface pricing point. The Ontario interface pricing point is noncontiguous to the PJM footprint that creates opportunities for market participants to engage in sham scheduling activities.

Overview: Section 10, Ancillary Services

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.

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 the first three months of 2023, the average primary reserve requirement was 2,541.1 MW in the RTO Zone and 2,521.6 in the MAD Subzone.
- **Market Concentration.** Both the Mid-Atlantic Dominion Subzone and the RTO Synchronized Reserve Zone Market were characterized by structural market power in the first three months of 2023. The average HHI for real-time synchronized reserve in the RTO Zone was 1362, which is classified as moderately concentrated. The average HHI for day-ahead synchronized reserve in the RTO Zone was 1321, which is classified as moderately concentrated. The average HHI for real-time synchronized reserve in the MAD Subzone was 4287, which is classified as highly concentrated. The average HHI for day-ahead synchronized reserve in the MAD Subzone was 2934, which is classified as highly concentrated.

Synchronized Reserve Market

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.

Market Structure

- **Supply.** In the first three months of 2023, the average supply of available synchronized reserve was 4,895.5 MW in the RTO Zone of which 2,172.4 MW was located in the MAD Subzone.
- **Demand.** The average hourly synchronized reserve requirement in the first three months of 2023 was 1,670.7 MW in the RTO Reserve Zone and 1,668.9 in the Mid-Atlantic Dominion Reserve Subzone.
- **Market Concentration.** The Mid-Atlantic Dominion Reserve Subzone Market was characterized by structural market power in the first three months of 2023. The average HHI for real-time synchronized reserve in the RTO Zone was 861, which is classified as unconcentrated. The average HHI for day-ahead synchronized reserve in the RTO Zone was 881, which is classified as unconcentrated. The average HHI for real-time synchronized reserve in the MAD Subzone was 3060, which is classified as highly concentrated. The average HHI for day-ahead synchronized reserve in the MAD Subzone was 2454, which is classified as highly 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 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. 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 real-time price for synchronized reserve for all cleared market intervals in the MAD Subzone was $1.26 per MWh in the first three months of 2023. The weighted average real-time price for synchronized reserve for all cleared intervals in the RTO Synchronized Reserve Zone was $0.55 per MWh in the first three months of 2023.

Nonsynchronized Reserve

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.

Market Structure

- **Supply.** In the first three months of 2023, the average supply of eligible and available nonsynchronized reserve was 940.1 MW in the RTO Zone, of which 594.3 MW was available in the MAD Subzone.

- **Demand.** Demand for nonsynchronized reserve is the primary reserve requirement, which is satisfied jointly by synchronized and nonsynchronized reserves.[173]

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 to be available for nonsynchronized reserves. For non-hydroelectric units, PJM calculates the MW available from a unit based on the unit's energy offer. Hydroelectric units set their offered reserve amount. For all units, the offer price of nonsynchronized reserve is $0 per MWh.[174]

Market Performance

- **Price.** The nonsynchronized reserve price is determined by the marginal primary reserve resource. In the first three months of 2023, the nonsynchronized reserve weighted average real-time price for all intervals in the RTO Reserve Zone was $0.18 per MWh and the weighted average day-ahead price was $0.93 per MWh. In the first three months of 2023, the nonsynchronized reserve weighted average real-time price for all intervals in the MAD Reserve Subzone was $0.52 per MWh and the weighted average day-ahead price was $2.65 per MWh.

30-Minute Reserve Market

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. Secondary reserves can only be used to satisfy the 30-minute reserve requirement.

173 See PJM. "PJM Manual 11: Energy & Ancillary Services Market Operations," § 4.1 Overview of the PJM Reserve Markets, Rev. 122 (Oct. 1, 2022).
174 See PJM. "PJM Manual 11: Energy & Ancillary Services Market Operations," § 4.2.3 Reserve Market Resource Offer Structure, Rev. 122 (Oct. 1, 2022).

Market Structure

- **Supply.** In the first three months of 2023, the average cleared 30-minute reserves was 16,489.8 MW in the day-ahead market and 4,443.3 MW in the real-time 30-minute market. Unlike the day-ahead market, the real-time market did not clear all available 30-minute reserves. In the first three months of 2023, an average of 14,528.5 MW of secondary reserves was scheduled in the day-ahead market and 2,170.3 MW of secondary reserves was scheduled in the real-time market.
- **Demand.** The 30-minute reserve requirement is the maximum of: 150 percent of the synchronized reserve requirement; the largest active gas contingency; or 3,000 MW. In the first three months of 2023, the average 30-minute requirement was 3,206.3 MW.
- **Market Concentration.** The 30-minute reserve market was unconcentrated in the first three months of 2023. The HHI for real-time 30-minute reserves was 881. The HHI for day-ahead 30-minute reserves was 439.

Market Behavior

In both the day-ahead and real-time 30-minute reserves markets, PJM uses 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. The amount of secondary reserve available from conventional resources are calculated based on the resources' energy offers. Hydroelectric resources, energy storage resources, and load response resources must specify their offered MW separately.

Market Performance

The average day-ahead price for secondary reserves in the first three months of 2023 was $0.00 per MWh. The average real-time price for secondary reserves in the first three months of 2023 was $0.00 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 the first three months of 2023, the average hourly offered supply of regulation for nonramp hours was 687.2 performance adjusted MW (709.1 effective MW). This was a decrease of 93.5 performance adjusted MW (a decrease of 70.9 effective MW) from the first three months of 2022. In the first three months of 2023, the average hourly offered supply of regulation for ramp hours was 1,043.4 performance adjusted MW (1,059.1 effective MW). This was a decrease of 103.8 performance adjusted MW (a decrease of 82.4 effective MW) from the first three months of 2022, when the average hourly offered supply of regulation was 1,147.2 performance adjusted MW (1,141.6 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 474.7 hourly average performance adjusted actual MW in the first three months of 2023. This is a decrease of 9.8 performance adjusted actual MW from the first three months of 2022, when the average hourly total regulation cleared performance adjusted actual MW for nonramp hours were 465.0 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 710.5 hourly average performance adjusted actual MW in the first three months of 2023. This is a decrease of 4.5 performance adjusted actual MW from the first three months of 2022, where the average hourly regulation cleared MW for ramp hours were 715.0 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 1.45 in the first three months of 2023 (1.67 in the first three months of 2022). The ratio of the average hourly offered supply of regulation to average hourly regulation demand (performance adjusted cleared MW) for ramp hours was 1.47 in the first three months of 2023 (1.58 in the first three months of 2022).
- **Market Concentration.** In the first three months of 2023, the three pivotal supplier test was failed in 93.2 percent of hours. In the first three months of 2023, the effective MW weighted average HHI of RegA resources was 2257 which is highly concentrated and the effective MW weighted average HHI of RegD resources was 1907 which is highly concentrated. The effective MW weighted average HHI of all resources was 1317, 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.[175] In the first three months of 2023, there were 150 resources following the RegA signal and 44 resources following the RegD signal.

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

Market Performance

- **Price and Cost.** The weighted average clearing price for regulation was $17.83 per MW of regulation in the first three months of 2023, a decrease of $27.40 per MW, or 60.6 percent, from the weighted average clearing price of $45.24 per MW in the first three months of 2022. The weighted average cost of regulation in the first three months of 2023 was $24.20 per MW of regulation, a decrease of 55.8 percent, from the weighted average cost of $54.76 per MW in the first three months of 2022.
- **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).[176]

In the first three months of 2023, total black start charges were $16.6 million, including $16.5 million in revenue requirement charges and $0.1 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 the first three months of 2023 ranged from $0 in the OVEC and REC Zones to $4.8 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.[177] RTOs and their customers are not required to compensate generation resources for such reactive capability.[178] In the first three months of 2023, customers in PJM, nevertheless, paid $96.3 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.[179] Reactive service charges are paid to units that operate in real time outside of their

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

177 OATT Attachment O.

178 *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).

179 OATT Schedule 2.

normal range at the direction of PJM for the purpose of providing reactive service.

Total reactive charges increased 0.5 percent from $95.8 million in the first three months of 2022 to $96.3 million in the first three months of 2023. Reactive capability charges increased 0.8 percent from $95.5 million in the first three months of 2022 to $96.3 million in the first three months of 2023. Total zonal reactive service charges ranged from $0 in the REC and OVEC Zones, to $13.4 million in the AEP Zone in the first three months of 2023.

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.[180] 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.[181] 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.[182] 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.

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

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

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

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

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.

Section 10 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 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.[183])
- The MMU recommends that the two signal regulation market design be replaced with a one signal regulation market design. (Priority: Medium. New recommendation. Status: Not adopted.)
- 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.[184] FERC rejected.[185])
- 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.[186])
- 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.[187])
- The MMU recommends enhanced documentation of the implementation of the regulation market design. (Priority: Medium. First reported 2010. Status: Not adopted. FERC rejected.[188])
- 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.)

183 162 FERC ¶ 61,295 (2018), *reh'g denied*, 170 FERC ¶ 61,259 (2020).

184 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.

185 162 FERC ¶ 61,295 (2018), *reh'g denied*, 170 FERC ¶ 61,259 (2020).

186 *Id.*

187 *Id.*

188 *Id.*

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.)
- 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 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 black start planning and coordination be on a regional basis and not on a zonal basis and that the costs of black start service be shared equally across the region. (Priority: medium. New recommendation. 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.[189] 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 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.[190] (Priority: Medium. First reported 2020. Status: Not adopted.)

Section 10 Conclusion

The design of the PJM Regulation Market is significantly flawed.[191] 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.[192] The PJM/MMU joint proposal addressed issues with the inconsistent application of the marginal benefit factor throughout the optimization and settlement process in the PJM Regulation Market. FERC

189 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.

190 *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>.

191 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).

192 18 CFR § 385.211.

rejected the joint proposal on March 30, 2018, as being noncompliant with Order No. 755.[193] The MMU and PJM separately filed requests for rehearing, which were denied by order issued March 26, 2020.[194]

The October 1, 2022, changes included 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 has occurred since October 2022, except during Winter Storm Elliott. 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.

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.

193 162 FERC ¶ 61,295 (2018).
194 170 FERC ¶ 61,259 (2020).

Overview: Section 11, Congestion and Marginal Losses

Congestion Cost

- **Total Congestion.** Total congestion costs decreased by $334.8 million or 65.6 percent, from $510.3 million in the first three months of 2022 to $175.5 million in the first three months of 2023.
- **Day-Ahead Congestion.** Day-ahead congestion costs decreased by $475.2 million or 67.7 percent, from $701.4 million in the first three months of 2022 to $226.2 million in the first three months of 2023.
- **Balancing Congestion.** Negative balancing congestion costs decreased by $140.4 million, from -$191.2 million in the first three months of 2022 to -$50.8 million in the first three months of 2023. Negative balancing explicit charges decreased by $18.4 million, from -$65.1 million in the first three months of 2022 to -$46.7 million in the first three months of 2023.
- **Real-Time Congestion.** Real-time congestion costs decreased by $765.1 million, from $936.3 million in the first three months of 2022 to $171.1 million in the first three months of 2023.
- **Monthly Congestion.** Monthly total congestion costs in the first three months of 2023 ranged from $26.8 million in March to $86.4 million in February.
- **Geographic Differences in CLMP.** Differences in CLMP between southern and eastern control zones in PJM were primarily a result of binding constraints on the Nottingham Series Reactor, the Beaumeade Circuit Breaker, the AP South Interface, the Gardners - Texas Eastern Line and the Bedington - Black Oak Interface.
- **Congestion Frequency.** Congestion frequency continued to be significantly higher in the day-ahead energy market than in the real-time energy market in the first three months of 2023. The number of congestion event

hours in the day-ahead energy market was about four and half times the number of congestion event hours in the real-time energy market.

Day-ahead congestion frequency decreased by 11.8 percent from 21,091 congestion event hours in the first three months of 2022 to 18,602 congestion event hours in the first three months of 2023.

Real-time congestion frequency decreased by 52.1 percent from 8,431 congestion event hours in the first three months of 2022 to 4,040 congestion event hours in the first three months of 2023.

- **Congested Facilities.** Day-ahead, congestion event hours decreased on all types of facilities except transformers.

  The Nottingham Series Reactor was the largest contributor to congestion costs in the first three months of 2023. With $44.1 million in total congestion costs, it accounted for 25.2 percent of the total PJM congestion costs in the first three months of 2023.

- **CT Price Setting Logic and Closed Loop Interface Related Congestion.** PJM's use of CT pricing logic officially ended with the implementation of fast start pricing on September 1, 2021. While CT pricing logic was officially discontinued by PJM on September 1, 2021, PJM continues to use a related logic to force inflexible units and demand response to be on the margin in both real time and day ahead. None of the PJM defined closed loop interfaces were binding in the first three months of 2023 or 2022.

- **Zonal Congestion.** AEP had the highest zonal congestion costs among all control zones in the first three months of 2023. AEP had $27.8 million in zonal congestion costs, comprised of $35.3 million in day-ahead congestion costs and -$7.5 million in balancing congestion costs.

Marginal Loss Cost

- **Total Marginal Loss Costs.** Total marginal loss costs decreased by $191.9 million or 48.8 percent, from $393.1 million in the first three months of 2022 to $201.2 million in the first three months of 2023. The loss MWh in PJM decreased by 731.1 GWh or 15.7 percent, from 4,648.0 GWh in the first three months of 2022 to 3,916.9 GWh in the first three months of 2023. The loss component of real-time LMP in the first three months of 2023 was $0.02, compared to $0.04 in the first three months of 2022.

- **Day-Ahead Marginal Loss Costs.** Day-ahead marginal loss costs decreased by $202.6 million or 47.6 percent, from $425.4 million in the first three months of 2022 to $222.8 million in the first three months of 2023.

- **Balancing Marginal Loss Costs.** Negative balancing marginal loss costs decreased by $10.7 million or 33.1 percent, from -$32.3 million in the first three months of 2022 to -$21.6 million in the first three months of 2023.

- **Total Marginal Loss Surplus.** The total marginal loss surplus decreased by $62.8 million or 48.9 percent, from $128.5 million in the first three months of 2022, to $65.7 million in the first three months of 2023.

- **Monthly Total Marginal Loss Costs.** Monthly total marginal loss costs in the first three months of 2023 ranged from $56.1 million in March to $78.8 million in January.

System Energy Cost

- **Total System Energy Costs.** Total system energy costs increased by $125.3 million or 48.0 percent, from -$260.8 million in the first three months of 2022 to -$135.6 million in the first three months of 2023.

- **Day-Ahead System Energy Costs.** Day-ahead system energy costs increased by $97.4 million or 34.9 percent, from -$279.1 million in the first three months of 2022 to -$181.7 million in the first three months of 2023.

- **Balancing System Energy Costs.** Balancing system energy costs increased by $28.6 million or 153.2 percent, from $18.7 million in the first three months of 2022 to $47.2 million in the first three months of 2023.

- **Monthly Total System Energy Costs.** Monthly total system energy costs in the first three months of 2023 ranged from -$59.2 million in January to -$37.5 million in March.

Section 11 Conclusion

Congestion is defined as the total payments by load in excess of the total payments to generation, excluding marginal losses. The level and distribution of congestion reflects the underlying characteristics of the power system, including the nature and defined capability of transmission facilities, the offers and geographic distribution of generation facilities, the level and geographic distribution of incremental bids and offers and the geographic and temporal distribution of load.

Total congestion costs decreased by $334.8 million or 65.6 percent, from $510.3 million in the first three months of 2022 to $175.5 million in the first three months of 2023 due to cold weather in January of 2022 and mild weather in the first three months of 2023.

Monthly total congestion costs ranged from $26.8 million in March to $86.4 million in February in the first three months of 2023.

The current ARR/FTR design does not ensure that load receives the rights to all congestion revenues. The congestion offset provided by ARRs and self scheduled FTRs in the first ten months of the 2022/2023 planning period was 75.6 percent. The cumulative offset of congestion by ARRs for the 2011/2012 planning period through the first ten months of the 2022/2023 planning period, using the rules effective for each planning period, was 69.0 percent. Load has received $3.8 billion less than load should have received from the 2011/2012 planning period through the first ten months of the 2022/2023 planning period.

Overview: Section 12, Planning

Generation Interconnection Planning

Existing Generation Mix

- As of March 31, 2023, PJM had a total installed capacity of 198,657.1 MW, of which 44,329.4 MW (22.3 percent) are coal fired steam units, 56,278.2 MW (28.3 percent) are combined cycle units and 33,452.6 MW (16.8 percent) are nuclear units. This measure of installed capacity differs from capacity market installed capacity because it includes energy only units, excludes all external units, and uses nameplate values for solar and wind resources.
- Of the 198,657.1 MW of installed capacity, 71,676.3 MW (36.1 percent) are from units older than 40 years, of which 34,642.3 MW (48.3 percent) are coal fired steam units, 191.0 MW (0.3 percent) are combined cycle units and 19,720.6 MW (27.5 percent) are nuclear units.

Generation Retirements[195]

- There are 54,355.9 MW of generation that have been, or are planned to be, retired between 2011 and 2026, of which 40,623.8 MW (74.7 percent) are coal fired steam units. Coal unit retirements are primarily a result of the inability of coal units to compete with efficient combined cycle units burning low cost natural gas.
- In the first three months of 2023, there were no generation retirements.
- As of March 31, 2023, there are 6,863.9 MW of generation that have requested retirement after March 31, 2023, of which 1,522.2 MW (22.2 percent) are located in the ATSI Zone. Of the generation requesting retirement in the ATSI Zone, 1,490.0 MW (97.9 percent) are coal fired steam units.

195 See PJM. Planning. "Generator Deactivations," (Accessed on March 31, 2023) <http://www.pjm.com/planning/services-requests/gen-deactivations.aspx>.

Generation Queue[196]

- On November 29, 2022, the Commission issued an order accepting PJM's tariff revisions to improve the queue process.[197] The new queue process includes modifications to implement a cluster/cycle based processing method to replace the first in/first out processing method.[198] This change will allow projects to move forward based on a first ready/first out analysis, where readiness is demonstrated through site control and financial milestones and there is an option to exit the study process early based on system impacts.
- As of March 31, 2023, 288,157.8 MW were in generation request queues in the status of active, under construction or suspended, an increase of 665.1 MW (0.2 percent) from the 287,492.7 MW the end of 2022.[199] Based on historical completion rates, 42,640.7 MW (14.8 percent) of new generation in the queue are expected to go into service. In the first three months of 2023, the AI2 queue window closed. As projects move through the queue process, projects can be removed from the queue due to incomplete or invalid data, withdrawn by the market participant or placed in service.
- As of March 31, 2023, 7,901 projects, representing 821,128.2 MW, have entered the queue process since its inception in 1998. Of those, 1,070 projects, representing 81,630.1 MW, went into service. Of the projects that entered the queue process, 3,499 projects, representing 451,340.4 MW (55.0 percent of the MW) withdrew prior to completion. Such projects may create barriers to entry for projects that would otherwise be completed, by taking up queue positions, increasing interconnection costs and creating uncertainty.
- In the first three months of 2023, 161.1 MW from the queue went in service. Of the 161.1 MW that went in service, 55.0 MW (34.1 percent) were combined cycle units, 55.0 MW (34.1 percent) were solar units and 51.1 MW (31.7 percent) were combustion turbine natural gas units.
- The number of queue entries increased during the past several years, primarily renewable projects. Of the 5,249 projects entered from January 2015 through March 2023, 3,915 projects (74.6 percent) were renewable. Of the 181 projects entered in the first three months of 2023, 164 projects (90.6 percent) were renewable. Renewable projects make up 76.3 percent of all projects in the queue and those projects account for 74.9 percent of the nameplate MW currently active, suspended or under construction in the queue as of March 31, 2023.
- But of the 215,812.0 MW of renewable projects in the queue, only 13,592.2 MW (6.3 percent) of capacity resources are expected to go into service, based on both historical completion rates and ELCC derate factors for battery, wind and solar.

Regional Transmission Expansion Plan (RTEP)

Market Efficiency Process

- There are significant issues with PJM's cost/ benefit analysis that should be addressed prior to approval of additional projects. PJM's cost/benefit analysis does not correctly account for the costs of increased congestion associated with market efficiency projects.
- Through March 31, 2023, PJM has completed five market efficiency cycles under Order No. 1000.[200]

PJM MISO Interregional Market Efficiency Process (IMEP)

- PJM and MISO developed a process to facilitate the construction of interregional projects in response to the Commission's concerns about interregional coordination along the PJM-MISO seam. This process, called the Interregional Market Efficiency Process (IMEP), operates on a two year study schedule and is designed to address forward looking congestion.

  But the use of an inaccurate cost/benefit method by PJM and the correct method by MISO results in an over allocation of the costs associated with

196 See PJM. Planning. "New Services Queue," (Accessed on March 31, 2023) <https://www.pjm.com/planning/services-requests/interconnection-queues.aspx>.
197 181 FERC ¶ 61,162 (2022).
198 See "Interconnection Process Reform," presented at April 27, 2022 meeting of the Members Committee. <https://www.pjm.com/-/media/committees-groups/committees/mc/2022/20220427/20220427-item-01a-1-interconnection-process-reform-presentation.ashx>.
199 The queue totals in this report are the winter net MW energy for the interconnection requests ("MW Energy") as shown in the queue.

200 See Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities, Order No. 1000, FERC Stats. & Regs. ¶ 31,323 (2011) (Order No. 1000), *order on reh'g*, Order No. 1000-A, 139 FERC ¶ 61,132 (2012).

joint PJM/MISO projects to PJM participants and in some cases approval of projects that do not pass an accurate cost-benefit test.

PJM MISO Targeted Market Efficiency Process (TMEP)

- PJM and MISO developed the Targeted Market Efficiency Process (TMEP) to facilitate the resolution of historic congestion issues that could be addressed through small, quick implementation projects.

Supplemental Transmission Projects

- Supplemental projects are defined to be "transmission expansions or enhancements that are not required for compliance with PJM criteria and are not state public policy projects according to the PJM Operating Agreement. These projects are used as inputs to RTEP models, but are not required for reliability, economic efficiency or operational performance criteria, as determined by PJM."[201] Supplemental projects are exempt from competition.
- The average number of supplemental projects in each expected in service year increased by 975.0 percent, from 20 for years 1998 through 2007 (pre Order No. 890) to 215 for years 2008 through 2023 (post Order 890).[202]

End of Life Transmission Projects

- An end of life transmission project is a project submitted for the purpose of replacing existing infrastructure that is at, or is approaching, the end of its useful life. End of life transmission projects should be included in the RTEP process and should be subject to a transparent, robust and clearly defined mechanism to permit competition to build the project. Under the current approach, end of life projects are exempt from competition.

Board Authorized Transmission Upgrades

- The Transmission Expansion Advisory Committee (TEAC) reviews proposals to improve transmission reliability in PJM and between PJM and neighboring regions. These proposals, which include reliability baseline, network, market efficiency and targeted market efficiency projects, as well as scope changes and project cancellations, but exclude supplemental and end of life projects, are periodically presented to the PJM Board of Managers for authorization.[203] In the first three months of 2023, the PJM Board approved $645.2 million in upgrades. As of March 31, 2023, the PJM Board has approved $42.2 billion in system enhancements since 1999.

Transmission Competition

- The MMU makes several recommendations related to the competitive transmission planning process. The recommendations include improved process transparency, incorporation of competition between transmission and generation alternatives and the removal of barriers to competition from nonincumbent transmission. These recommendations would help ensure that the process is an open and transparent process that results in the most competitive solutions.
- On May 24, 2018, the PJM Markets and Reliability Committee (MRC) approved a motion that required PJM, with input from the MMU, to develop a comparative framework to evaluate the quality and effectiveness of competitive transmission proposals with binding cost containment proposals compared to proposals from incumbent and nonincumbent transmission companies without cost containment provisions.

Qualifying Transmission Upgrades (QTU)

- A Qualifying Transmission Upgrade (QTU) is an upgrade to the transmission system that increases the Capacity Emergency Transfer Limit (CETL) into an LDA and can be offered into capacity auctions as capacity. Once a QTU is in service, the upgrade is eligible to continue to offer the approved incremental import capability into future RPM Auctions. As of March 31, 2023, no QTUs have cleared a Base Residual Auction or an Incremental Auction.

201 See PJM. "Transmission Construction Status," (Accessed on March 31, 2023) <http://www.pjm.com/planning/rtep-upgrades-status/construct-status.aspx>.

202 See *Preventing Undue Discrimination and Preference in Transmission Service*, Order No. 890, 118 FERC ¶ 61,119, *order on reh'g*, Order No. 890-A, 121 FERC ¶ 61,297 (2007), *order on reh'g*, Order No. 890-B, 123 FERC ¶ 61,299 (2008), *order on reh'g*, Order No. 890-C, 126 FERC ¶ 61,228, *order on clarification*, Order No. 890-D, 129 FERC ¶ 61,126 (2009).

203 Supplemental Projects, including the end of life subset of supplemental projects, do not require PJM Board of Managers authorization.

Transmission Facility Outages

- PJM maintains a list of reportable transmission facilities. When the reportable transmission facilities need to be taken out of service, PJM transmission owners are required to report planned transmission facility outages as early as possible. PJM processes the transmission facility outage requests according to rules in PJM's Manual 3 to decide if the outage is on time or late and whether or not they will allow the outage.[204]
- There were 15,651 transmission outage requests submitted in the first ten months of the 2022/2023 planning period. Of the requested outages, 76.4 percent were planned for less than or equal to five days and 9.1 percent were planned for greater than 30 days. Of the requested outages, 39.2 percent were late according to the rules in PJM's Manual 3.

Section 12 Recommendations

Generation Retirements

- The MMU recommends that the question of whether Capacity Interconnection Rights (CIRs) should persist after the retirement of a unit be addressed. The rules need to ensure that incumbents cannot exploit control of CIRs to block or postpone entry of competitors.[205] (Priority: Medium. First reported 2013. Status: Partially adopted, 2012.)

Generation Queue

- Given the significance of data to market participants and regulators, the MMU recommends that all queue data and supplemental, network and baseline project data, including projected in service dates and estimated and final costs, be regularly updated with accurate and verifiable data. (Priority: High. New recommendation. Not adopted.)
- The MMU recommends that barriers to entry be addressed in a timely manner in order to help ensure that the capacity market will result in the entry of new capacity to meet the needs of PJM market participants. (Priority: Low. First reported 2012. Status: Not adopted.)
- The MMU recommends improvements in queue management including that PJM establish a review process to ensure that projects are removed from the queue if they are not viable, as well as a process to allow commercially viable projects to advance in the queue ahead of projects which have failed to make progress, subject to rules to prevent gaming.[206] (Priority: Medium. First reported 2013. Status: Partially adopted.)
- The MMU recommends continuing analysis of the study phase of PJM's transmission planning to reduce the need for postponements of study results, to decrease study completion times, and to improve the likelihood that a project at a given phase in the study process will successfully go into service.[207] (Priority: Medium. First reported 2014. Status: Partially adopted.)
- The MMU recommends outsourcing interconnection studies to an independent party to avoid potential conflicts of interest. Currently, these studies are performed by incumbent transmission owners under PJM's direction. This creates potential conflicts of interest, particularly when transmission owners are vertically integrated and the owner of transmission also owns generation. (Priority: Low. First reported 2013. Status: Not adopted.)

Market Efficiency Process

- The MMU recommends that the market efficiency process be eliminated because it is not consistent with a competitive market design. (Priority: Medium. First reported 2019. Status: Not adopted.)
- The MMU recommends that, if the market efficiency process is retained, PJM modify the rules governing cost/benefit analysis, the evaluation process for selecting among competing market efficiency projects and cost allocation for economic projects in order to ensure that all costs, including increased congestion costs and the risk of project cost increases, in all zones are included in order to ensure that the correct metrics are used for defining benefits. (Priority: Medium. First reported 2018. Status: Not adopted.)

204 See "PJM Manual 03: Transmission Operations," Rev. 63 (November 16, 2022).
205 See Comments of the Independent Market Monitor for PJM, Docket No. ER12-1177-000 (March 12, 2012) <http://www.monitoringanalytics.com/Filings/2012/IMM_Comments_ER12-1177-000_20120312.PDF>.
206 PJM Filing, FERC Docket No. ER22-2110-000 (June 14, 2022); 181 FERC ¶ 61,162 (2022).
207 Ibid.

Comparative Cost Framework

- The MMU recommends that PJM modify the project proposal templates to include data necessary to perform a detailed project lifetime financial analysis. The required data includes, but is not limited to: capital expenditure; capital structure; return on equity; cost of debt; tax assumptions; ongoing capital expenditures; ongoing maintenance; and expected life. (Priority: Medium. First reported 2020. Status: Not adopted.)

Transmission Competition

- The MMU recommends, to increase the role of competition, that the exemption of supplemental projects from the Order No. 1000 competitive process be terminated and that the basis for all such exemptions be reviewed and modified to ensure that the supplemental project designation is not used to exempt transmission projects from a transparent, robust and clearly defined mechanism to permit competition to build such projects or to effectively replace the RTEP process. (Priority: Medium. First reported 2017. Status: Not adopted. Rejected by FERC.)[208]
- The MMU recommends, to increase the role of competition, that the exemption of end of life projects from the Order No. 1000 competitive process be terminated and that end of life transmission projects be included in the RTEP process and should be subject to a transparent, robust and clearly defined mechanism to permit competition to build such projects. (Priority: Medium. First reported 2019. Status: Not adopted. Rejected by FERC.)[209]
- The MMU recommends that PJM enhance the transparency and queue management process for nonincumbent transmission investment. Issues related to data access and complete explanations of cost impacts should be addressed. The goal should be to remove barriers to competition from nonincumbent transmission providers. (Priority: Medium. First reported 2015. Status: Not adopted.)
- The MMU recommends that PJM continue to incorporate the principle that the goal of transmission planning should be the incorporation of transmission investment decisions into market driven processes as much as possible. (Priority: Low. First reported 2001. Status: Not adopted.)
- The MMU recommends the creation of a mechanism to permit a direct comparison, or competition, between transmission and generation alternatives, including which alternative is less costly and who bears the risks associated with each alternative. (Priority: Low. First reported 2013. Status: Not adopted.)
- The MMU recommends that PJM establish fair terms of access to rights of way and property, such as at substations, in order to remove any barriers to entry and permit competition between incumbent transmission providers and nonincumbent transmission providers in the RTEP. (Priority: Medium. First reported 2014. Status: Not adopted.)
- The MMU recommends that rules be implemented to permit competition to provide financing for transmission projects. This competition could reduce the cost of capital for transmission projects and significantly reduce total costs to customers. (Priority: Low. First reported 2013. Status: Not adopted.)
- The MMU recommends that storage resources not be includable as transmission assets for any reason. (Priority: High. First reported 2020. Status: Not adopted.)

Cost Allocation

- The MMU recommends a comprehensive review of the ways in which the solution based dfax is implemented. The goal for such a process would be to ensure that the most rational and efficient approach to implementing the solution based dfax method is used in PJM. Such an approach should allocate costs consistent with benefits and appropriately calibrate the incentives for investment in new transmission capability. No replacement approach should be approved until all potential alternatives, including the status quo, are thoroughly reviewed. (Priority: Medium. First reported 2020. Status: Not adopted.)

208 The FERC accepted tariff provisions that exclude supplemental projects from competition in the RTEP. 162 FERC ¶ 61,129 (2018), *reh'g denied*, 164 FERC ¶ 61,217 (2018).

209 In recent decisions addressing competing proposals on end of life projects, the Commission accepted a transmission owner proposal excluding end of life projects from competition in the RTEP process, 172 FERC ¶ 61,136 (2020), *reh'g denied*, 173 FERC ¶ 61,225 (2020), and rejected a proposal from PJM stakeholders that would have included end of life projects in competition in the RTEP process, 173 FERC ¶ 61,242 (2020).

- The MMU recommends changing the minimum distribution factor in the allocation from 0.01 to 0.00 and adding a threshold minimum usage impact on the line.[210] (Priority: Medium. First reported 2015. Status: Not adopted.)

Transmission Line Ratings

- The MMU recommends that all PJM transmission owners use the same methods to define line ratings and that all PJM transmission owners implement dynamic line ratings (DLR), subject to NERC standards and guidelines, subject to review by NERC, PJM and the MMU, and approval by FERC. (Priority: Medium. First reported 2019. Status: Not adopted.)

Transmission Facility Outages

- The MMU recommends that PJM reevaluate all transmission outage tickets as on time or late as if they were new requests when an outage is rescheduled, create options for late requests based on the reasons, and apply the modified rules for late submissions to any such outages. (Priority: Low. First reported 2014. Status: Not adopted.)
- The MMU recommends that PJM draft a clear definition of the congestion analysis required for transmission outage requests and associated triggers, including both the extent of overloaded facilities and the level of economic congestion, to include in Manual 3 after appropriate review. (Priority: Medium. First reported 2015. Status: Not adopted.)
- The MMU recommends that PJM create options for late requests based on the reasons, and modify the rules to reduce or eliminate the approval of late outage requests submitted or rescheduled after the FTR auction bidding opening date, based on those options. (Priority: Low. First reported 2015. Status: Not adopted.)
- The MMU recommends that PJM not permit transmission owners to divide long duration outages into smaller segments to avoid complying with the requirements for long duration outages. (Priority: Low. First reported 2015. Status: Not adopted.)

210 See *2015 State of the Market Report for PJM*, Volume II, Section 12: Generation and Transmission Planning, at 463, Cost Allocation Issues.

Section 12 Conclusion

The goal of the PJM market design should be to enhance competition and to ensure that competition is the core element of all PJM markets. But transmission investments have not been fully incorporated into competitive markets. The construction of new transmission facilities has significant impacts on the energy and capacity markets. But when generating units retire or load increases, there is no market mechanism in place that would require or even permit direct competition between transmission and generation to meet loads in the affected area. In addition, despite FERC Order No. 1000, there is not yet a transparent, robust and clearly defined mechanism to permit competition to build transmission projects, to ensure that competitors provide a total project cost cap, or to obtain least cost financing through the capital markets.

The MMU recognizes that the Commission has issued orders that are inconsistent with the recommendations of the MMU and that PJM cannot unilaterally modify those directives. It remains the recommendation of the MMU that the PJM rules for competitive transmission development through the RTEP should build upon FERC Order No. 1000 to create real competition between incumbent transmission providers and nonincumbent transmission providers. The ability of transmission owners to block competition for supplemental projects and end of life projects and the reasons for that policy should be reevaluated. PJM should enhance the transparency and queue management process for nonincumbent transmission investment. Issues related to data access and complete explanations of cost impacts should be addressed. The goal should be to remove barriers to competition from nonincumbent transmission.

Another element of opening competition would be to consider transmission owners' ownership of property and rights of way at or around transmission substations. In many cases, the land acquired included property intended to support future expansion of the grid. Incumbents have included the costs of the property in their rate base, paid for by customers. PJM now has the responsibility for planning the development of the grid under its RTEP process. Property bought to facilitate future expansion should be a part of the RTEP process and be made available to all providers on equal terms.

The process for determining the reasonableness or purpose of supplemental transmission projects that are asserted to be not needed for reliability, economic efficiency or operational performance as defined under the RTEP process needs additional oversight and transparency. If there is a need for a supplemental project, that need should be clearly defined and there should be a transparent, robust and clearly defined mechanism to permit competition to build the project. If there is no defined need for of a supplemental project for reliability, economic efficiency or operational performance then the project should not be included in rates.

Managing the generation queues is a complex process. The PJM queue evaluation process will be significantly improved, based on the proposal submitted by PJM on June 14, 2022, and approved by FERC on November 29, 2022.[211] [212] The new rules include significant modifications to the interconnection process designed to address some of the key underlying issues and significantly improve the efficiency of the process. These modifications include process efficiency enhancements, recognition of project clusters affecting the same transmission facilities, incentives to reduce the entry of speculative projects in the queue, and incentives to remove projects that are not expected to reach commercial operation. The proposed solution should help to reduce backlog and to remove projects that are not viable earlier to help improve the overall efficiency of the queue process.

The impact of the modifications to the queue process will need to be evaluated to determine if they successfully remove projects from the queue if they are not viable, and allow commercially viable projects to advance in the queue ahead of projects which have failed to make progress. The behavior of project developers also creates issues with queue management. When developers put multiple projects in the queue to maintain their own optionality while planning to build only one they also affect all the projects that follow them in the queue. Project developers may also enter speculative projects in the queue and then put the project in suspended status while they address financing. The impacts of such behavior and the incentives for such behavior are addressed in the new process which includes nonrefundable fees, credit requirements, enhanced site control, elimination of the ability to suspend a project and milestone requirements. The impact of these aspects of the revised interconnection process should continue to be evaluated to ensure that they are having the desired effect on project developer behavior. The PJM queue evaluation process should continue to be improved to help ensure that barriers to competition for new generation investments are not created. Issues that need to be addressed include the ownership rights to CIRs and whether transmission owners should perform interconnection studies.

The roles and efficiency of PJM, TOs and developers in the queue process all need to be examined and enhanced in order to help ensure that the queue process can function effectively and efficiently as the gateway to competition in the energy and capacity markets and not as a barrier to competition.

The Commission should require PJM, for example, to enhance the transparency and queue management process for nonincumbent transmission investment. Issues related to data access and complete explanations of cost impacts should be addressed. The goal should be to remove barriers to competition from nonincumbent transmission.

The addition of a planned transmission project changes the parameters of the capacity auction for the area, changes the amount of capacity needed in the area, changes the capacity market supply and demand fundamentals in the area and may effectively forestall the ability of generation to compete. But there is no mechanism to permit a direct comparison, let alone competition, between transmission and generation alternatives. There is no mechanism to evaluate whether the generation or transmission alternative is less costly, whether there is more risk associated with the generation or transmission alternatives, or who bears the risks associated with each alternative. Creating such a mechanism should be an explicit goal of PJM market design.

The current market efficiency process does exactly the opposite by permitting transmission projects to be approved without competition from generation. The broader issue is that the market efficiency project approach explicitly allows transmission projects to compete against future generation projects, but without allowing the generation projects to compete. Projecting speculative

211 See *PJM*, Docket No. ER22-2110 (June 14, 2022).
212 181 FERC ¶ 61,162 (2022).

transmission related benefits for 15 years based on the existing generation fleet and existing patterns of congestion eliminates the potential for new generation to respond to market signals. The market efficiency process allows assets built under the cost of service regulatory paradigm to displace generation assets built under the competitive market paradigm. In addition, there are significant issues with PJM's current cost/benefit analysis which cause it to consistently overstate the potential benefits of market efficiency projects. The market efficiency process is misnamed. The MMU recommends that the market efficiency process be eliminated.

In addition, the use of an inaccurate cost-benefit method by PJM and the correct method by MISO results in an over allocation of the costs associated with joint PJM/MISO projects to PJM participants and in some cases approval of projects that do not pass an accurate cost-benefit test.

If it is retained, there are significant issues with PJM's cost/benefit analysis that should be addressed prior to approval of additional projects. The current cost/benefit analysis for a regional project, for example, explicitly and incorrectly ignores the increased congestion in zones that results from an RTEP project when calculating the energy market benefits. All costs should be included in all zones and LDAs. The definition of benefits should also be reevaluated.

The cost/benefit analysis should also account for the fact that the transmission project costs are not subject to cost caps and may exceed the estimated costs by a wide margin. When actual costs exceed estimated costs, the cost benefit analysis is effectively meaningless and low estimated costs may result in inappropriately favoring transmission projects over market generation projects. The risk of cost increases for transmission projects should be incorporated in the cost benefit analysis.

There are currently no market incentives for transmission owners to plan, submit and complete transmission outages in a timely and efficient manner. Requiring transmission owners to pay does not create an effective incentive when those payments are passed through to transmission customers. The process for the submission of planned transmission outages needs to be carefully reviewed and redesigned to limit the ability of transmission owners to submit transmission outages that are late for FTR auction bid submission dates and are late for the day-ahead energy market and that have large and unnecessary impacts on the PJM energy market. The submission of late transmission outages can inappropriately affect market outcomes when market participants do not have the ability to modify market bids and offers. The PJM process for evaluating the congestion impact of transmission outages needs to be clearly defined and upgraded to provide for management of transmission outages to minimize market impacts. The MMU continues to recommend that PJM draft a clear and expanded definition of the congestion analysis required for transmission outage requests that is incorporated in the PJM Market Rules. PJM Manual 38 currently defines congestion resulting from a transmission outage as an overload on transmission facilities rather than using the general economic definition of congestion resulting from out of merit generation to control constraints. PJM does not currently evaluate the economic impact of congestion when reviewing proposed transmission outages.[213]

The treatment by PJM and Dominion Virginia Power of the outage for the Lanexa – Dunnsville Line illustrates some of the issues with the current process. The outage was submitted and delayed more than once. PJM's analysis of expected congestion did not highlight the magnitude of the issue. Dominion Virginia Power did not stage the outage so as to minimize market disruption and congestion until after there were significant disruptions and congestion.

As an example of the complexities of defining the benefits of transmission investments, the reduction in congestion is frequently and incorrectly cited as a metric of benefits.

Congestion is frequently misunderstood. Congestion is not static. Congestion exhibits dynamic intertemporal variability and dynamic locational variability. More importantly, congestion is not the correct metric for evaluating the potential benefits of enhancing the transmission grid.

There is not a secular trend towards increasing congestion in PJM. Congestion is volatile on a monthly basis. Congestion is also volatile on an hourly and

213 PJM, "Manual 38: Operations Planning," Rev. 16 (Jan. 25, 2023), p20.

daily basis. For example, higher congestion can result from changes in seasonal and daily/hourly fuel costs.

The level and distribution of congestion at a point in time is a function of the location and size of generating units, the relative costs of the fuels burned and the associated marginal costs of generating units, the location and size of load and the locational capability of the transmission grid. Each of these factors changes over time.

The geographic distribution of congestion is dynamic. The nature and location of congestion in the PJM system has changed significantly over the last 10 years and continues to change. The nature and location of congestion in PJM can also change from one day to the next as a result of changes in relative fuel costs. As a result, building transmission to address a specific pattern of congestion does not make sense, unless the technology can be easily moved to new locations as conditions change. The transmission system is only one of many reasons that congestion exists. The dynamic nature of congestion and the multiple, interactive causes of congestion make it virtually impossible to identify the standalone impacts of an individual transmission investment on future congestion. It is possible, for example, that congestion occurring during a period of a few days in the winter as a result of very high fuel prices, significantly increases the reported level of congestion for the entire year. This has occurred in PJM. It would be a mistake to consider that level of congestion to be a signal to build transmission.

At a more fundamental level, congestion is not the correct metric for evaluating the potential benefits of enhancing the transmission grid. When there are binding transmission constraints and locational price differences, load pays more for energy than generation is paid to produce that energy. The difference is congestion. Congestion is neither good nor bad, but is a direct measure of the extent to which there are multiple marginal generating units with different offers dispatched to serve load as a result of transmission constraints. Congestion occurs when available, least-cost energy cannot be delivered to all load because transmission facilities are not adequate to deliver that energy to one or more areas, and higher cost units in the constrained area(s) must be dispatched to meet the load. The result is that the price of energy in the constrained area(s) is higher than in the unconstrained area. Load in the constrained area pays the higher price for all energy including energy from low cost generation and energy from high cost generation, while only high cost generators are paid the high price at their bus and low cost generators are paid only the low price at their bus.

If FTRs worked perfectly and were assigned directly to load, FTRs would return all congestion to the load that paid the congestion. Congestion is not a cost, it is an accounting result of a market based on locational energy prices in which all load in a constrained area pays the higher single market clearing locational price, resulting in excess payments by load that are not paid to generation, which should be returned to load.

Counterintuitively, congestion actually increases when the transmission capacity between areas with lower cost generation and areas with higher cost generation increases but does not fully eliminate the need for some higher cost local generation. The smaller the amount of higher cost local generation needed to meet load, the more of the local load is met via low cost generation delivered over the transmission system and therefore the higher is the difference between what load pays and generation receives, congestion.

The PJM Regional Transmission Expansion Plan (RTEP) successfully addresses the need for transmission investment to reliably meet load. Together with the requirement that new generation pay interconnection costs, the RTEP process has resulted in the appropriate level of new transmission investment in PJM. There is no evidence that the PJM planning process is not adequate to meet the requirements of the PJM markets. Additional transmission investment is not a panacea. Transmission investment is expensive and long lived and it is essential that transmission investments be carefully planned for clearly identified needs in order to ensure that power markets can continue to provide reliable service at a competitive price.

Overview: Section 13, FTRs and ARRs

Auction Revenue Rights

Market Structure

- **ARR Ownership.** In the 2022/2023 planning period ARRs were allocated to 1,563 individual participants, held by 133 parent companies. ARR ownership for the 2022/2023 planning period was unconcentrated with an HHI of 584.

Market Behavior

- **Self Scheduled FTRs.** For the 2022/2023 planning period, 26.0 percent of eligible ARRs were self scheduled as FTRs.

Market Performance

- **ARRs as an Offset to Congestion.** ARRs have not served as an effective mechanism to return all congestion revenues to load. For the first ten months of the 2022/2023 planning period, ARRs and self scheduled FTRs offset 75.6 percent of total congestion. Congestion payments by load in some zones were more than offset and congestion payments in some zones were less than offset. Load has been underpaid congestion revenues by $3.8 billion from the 2011/2012 planning period through the first ten months of the 2022/2023 planning period. The cumulative offset for that period was 69.0 percent of total congestion.
- **ARR Payments.** For the first ten months of the 2022/2023 planning period, the ARR target allocations, which are based on the nodal price differences from the Annual FTR Auction, were $1,343.2 million, while PJM collected $1,660.4 million from the combined Long Term, Annual and Monthly Balance of Planning Period FTR Auctions. For the 2021/2022 planning period, the ARR target allocations were $634.2 million while PJM collected $812.6 million from the combined Annual and Monthly Balance of Planning Period FTR Auctions.
- **Residual ARRs.** Residual ARRs are only available on contract paths prorated in Stage 1 of the annual ARR allocation, are only effective for single, whole months and cannot be self scheduled. Residual ARR clearing prices are based on monthly FTR auction clearing prices. Residual ARRs with negative target allocations are not allocated to participants. Instead they are removed and the model is rerun.

  In the first ten months of the 2022/2023 planning period, PJM allocated a total of 27,924.0 MW of residual ARRs with a total target allocation of $31.0 million, up from 24,023.5 MW, with a total target allocation of $16.2 million, in the same period of the 2021/2022 planning period.
- **ARR Reassignment for Retail Load Switching.** There were 30,917 MW of ARRs associated with $1,325,600 of revenue that were reassigned for the first ten months of the 2022/2023 planning period. There were 32,935 MW of ARRs associated with $568,200 of revenue that were reassigned in the 2021/2022 planning period.

Financial Transmission Rights

Market Design

- **Monthly Balance of Planning Period FTR Auctions.** The design of the Monthly Balance of Planning Period FTR Auctions includes auctions for each remaining month in the planning period.

Market Structure

- **Patterns of Ownership.** For the Monthly Balance of Planning Period Auctions, financial entities purchased 83.1 percent of prevailing flow and 92.4 percent of counter flow FTRs in the first three months of 2023. Financial entities owned 75.2 percent of all prevailing and counter flow FTRs, including 64.3 percent of all prevailing flow FTRs and 87.1 percent of all counter flow FTRs during the first three months of 2023. Self scheduled FTRs account for 4.8 percent of all FTRs held.
- **Market Concentration.** In the Monthly Balance of Planning Period Auctions for the first ten months of the 2022/2023 planning period, ownership of cleared prevailing flow bids was unconcentrated in 93.3 percent of periods and moderately concentrated in 6.7 percent of periods. Ownership of cleared counter flow bids was unconcentrated in 66.7 percent of periods and moderately concentrated in 33.3 percent of periods.

Market Behavior

- **Sell Offers.** In a given auction, market participants can sell FTRs acquired in preceding auctions or preceding rounds of auctions. In the Monthly Balance of Planning Period FTR Auctions for the first ten months of the 2022/2023 planning period, total participant FTR sell offers were 20,815,305 MW.
- **Buy Bids.** The total FTR buy bids from the Monthly Balance of Planning Period FTR Auctions for the first ten months of the 2022/2023 planning were 37,743,885 MW.
- **FTR Forfeitures.** Total FTR forfeitures were $3.4 million for the first ten months of the 2022/2023 planning period.
- **Credit.** There was one collateral default and zero payment defaults in the first three months of 2023. Market Performance.
- **Quantity** In the first ten months of the 2022/2023 planning period, Monthly Balance of Planning Period FTR Auctions cleared 6,672,139 MW (17.7 percent) of FTR buy bids and 3,231,664 MW (15.5 percent) of FTR sell offers. For the same period of the 2021/2022 planning period, Monthly Balance of Planning Period FTR Auctions cleared 5,254,0456 MW (19.3 percent) of FTR buy bids and 2,971,061 MW (19.9 percent) of FTR sell offers.
- **Price.** The weighted average buy bid cleared FTR price in the Monthly Balance of Planning Period FTR Auctions for all periods in the first ten months of the 2022/2023 planning period was $0.49 per MWh.
- **Revenue.** The Monthly Balance of Planning Period FTR Auctions resulted in net revenue of $102.2 million in the first ten months of the 2022/2023 planning period, up from $46.1 million for the same time period in the 2021/2022 planning period.
- **Revenue Adequacy.** FTRs were paid 100.0 percent of the target allocations for the first ten months of the 2022/2023 planning period, including distribution of the current surplus revenue.
- **Profitability.** FTR profitability is the difference between the revenue received directly from holding an FTR plus any revenue from the sale of an FTR, and the cost of buying the FTR. In the first 10 months of the 2022/2023 planning period, profits for all participants were $393.1 million. In the first 10 months of the 2022/2023 planning period, physical entities received $23.5 million in profits on FTRs purchased directly (not self scheduled), down from $201.3 million in profits in the same time period in the 2021/2022 planning period. Financial entities received $369.6 million in profits, down from $598.4 million profits in the same time period in the 2021/2022 planning period.

Section 13 Recommendations

Market Design

- The MMU recommends that the current ARR/FTR design be replaced with defined congestion revenue rights (CRRs). A CRR is the right to actual congestion that is paid by physical load at a specific bus, zone or aggregate. (Priority: High. First reported 2015. Status: Not adopted.)

ARR

- The MMU recommends that the ARR/FTR design be modified to ensure that the rights to all congestion revenues are assigned to load. (Priority: High. First reported 2015. Status: Not adopted.)
- The MMU recommends that all historical generation to load paths be eliminated as a basis for assigning ARRs. The MMU recommends that the current design be replaced with a design in which the rights to actual congestion paid are assigned directly to the load that paid that congestion by node. (Priority: High. First reported 2015. Status: Partially adopted.)
- The MMU recommends that, under the current FTR design, the rights to all congestion revenue be allocated as ARRs prior to sale as FTRs. Reductions for outages and increased system capability should be reserved for ARRs rather than sold in the Long Term FTR Auction. (Priority: High. First reported 2017. Status: Not adopted.)
- The MMU recommends that IARRs be eliminated from PJM’s tariff, but that if IARRs are not eliminated, IARRs should be subject to the same proration rules that apply to all other ARR rights. (Priority: Low. First reported 2018. Status: Not adopted.)

FTR

- The MMU recommends that FTR funding be based on total congestion, including day-ahead and balancing congestion. (Priority: High. First reported 2017. Status: Not adopted.)
- The MMU recommends that bilateral transactions be eliminated and that all FTR transactions occur in the PJM market. (Priority: High. First reported Q1 2022. Status: Not adopted.)[214]
- The MMU recommends a requirement that the details of all bilateral FTR transactions be reported to PJM. (Priority: High. First reported 2020. Status: Not adopted.)
- The MMU recommends that PJM continue to evaluate the bilateral indemnification rules and any asymmetries they may create. (Priority: Low. First reported 2018. Status: Not adopted.)
- The MMU recommends that PJM reduce FTR sales on paths with persistent overallocation of FTRs, including a clear definition of persistent overallocation and how the reduction will be applied. (Priority: High. First reported 2013. Status: Partially adopted, 2014/2015 planning period.)
- The MMU recommends that PJM eliminate generation to generation paths and all other paths that do not represent the delivery of power to load. (Priority: High. First reported 2018. Status: Not adopted.)
- The MMU recommends that the Long Term FTR product be eliminated. If the Long Term FTR product is not eliminated, the Long Term FTR Market should be modified so that the supply of prevailing flow FTRs in the Long Term FTR Market is based solely on counter flow offers in the Long Term FTR Market. (Priority: High. First reported 2017. Status: Not adopted.)
- The MMU recommends that PJM improve transmission outage modeling in the FTR auction models, including the use of probabilistic outage modeling. (Priority: Low. First reported 2013. Status: Not adopted.)

214 If adopted, this recommendation would replace the next two recommendations.

Surplus

- The MMU recommends that all FTR auction revenue be distributed to ARR holders monthly, regardless of FTR funding levels. (Priority: High. First reported 2015. Status: Not adopted.)
- The MMU recommends that, under the current FTR design, all congestion revenue in excess of FTR target allocations be distributed to ARR holders on a monthly basis. (Priority: High. First reported 2018. Status: Not adopted.)
- The MMU recommends that FTR auction revenues not be used by PJM to buy counter flow FTRs for the purpose of improving FTR payout ratios.[215] (Priority: High. First reported 2015. Status: Not adopted.)

FTR Subsidies

- The MMU recommends that PJM eliminate portfolio netting to eliminate cross subsidies among FTR market participants. (Priority: High. First reported 2012. Status: Not adopted. Rejected by FERC.)
- The MMU recommends that PJM eliminate subsidies to counter flow FTRs by applying the payout ratio to counter flow FTRs in the same way the payout ratio is applied to prevailing flow FTRs. (Priority: High. First reported 2012. Status: Not adopted.)
- The MMU recommends that PJM eliminate geographic cross subsidies. (Priority: High. First reported 2013. Status: Not adopted.)
- The MMU recommends that PJM examine the mechanism by which self scheduled FTRs are allocated when load switching among LSEs occurs throughout the planning period. (Priority: Low. First reported 2011. Status: Not adopted.)

FTR Liquidation

- The MMU recommends that the FTR portfolio of a defaulted member be canceled rather than liquidated or allowed to settle as a default cost on the membership. (Priority: High. First reported 2018. Status: Not adopted.)

215 See "PJM Manual 6: Financial Transmission Rights," Rev. 29 (Sep. 1, 2022).

Credit

- The MMU recommends the use of a 99 percent confidence interval when calculating initial margin requirements for FTR market participants, in order to assign the cost of managing risk to the FTR holders who benefit or lose from their FTR positions. (Priority: High. First reported 2021. Status: Not adopted.)

Section 13 Conclusion

Solutions

The annual ARR allocation should be designed to ensure that the rights to all congestion revenues are assigned to load, without requiring contract path or point to point physical or financial transmission rights that are inconsistent with the network based delivery of power and the actual way congestion is generated in security constrained LMP markets. When there are binding transmission constraints and locational price differences, load pays more for energy than generation is paid to produce that energy. The difference is congestion. As a result, congestion belongs to load and should be returned to load.

The current contract path based design should be replaced with a design in which the rights to actual congestion paid are assigned directly to the load that paid that congestion by node. The assigned right is to the actual difference between load payments, both day-ahead and balancing, and revenues paid to the generation used to serve that load. The load can retain the right to the congestion revenues or sell the rights through auctions. The correct assignment of congestion revenues to load is fully consistent with retaining FTR auctions for the sale by load of their congestion revenue rights.

Issues

If the original PJM FTR approach had been designed to return congestion revenues to load without use of the generation to load contract paths, and if the distortions subsequently introduced into the FTR design not been added, many of the subsequent issues with the FTR design and complex redesigns would have been avoided. PJM would not have had to repeatedly intervene in the functioning of the FTR system in an effort to meet the artificial and incorrectly defined goal of revenue adequacy.

PJM has persistently and subjectively intervened in the FTR market in order to affect the payments to FTR holders. These interventions are not appropriate. For example, in the 2014/2015, 2015/2016 and 2016/2017 planning periods, PJM significantly reduced the allocation of ARR capacity, and FTRs, in order to guarantee full FTR funding. PJM reduced system capability in the FTR auction model by including more outages, reducing line limits and including additional constraints. PJM's modeling changes resulted in significant reductions in Stage 1B and Stage 2 ARR allocations, a corresponding reduction in the available quantity of FTRs, a reduction in congestion revenues assigned to ARRs, and an associated surplus of congestion revenue relative to FTR target allocations. This also resulted in a significant redistribution of ARRs among ARR holders based on differences in allocations between Stage 1A and Stage 1B ARRs. Starting in the 2017/2018 planning period, with the allocation of balancing congestion and M2M payments to load rather than FTRs, PJM increased system capability allocated to Stage 1B and Stage 2 ARRs, but continued to conservatively select outages to manage FTR funding levels.

PJM has intervened aggressively in the FTR market since its inception in order to meet various subjective objectives including so called revenue adequacy. PJM should not intervene in the FTR market to subjectively manage FTR funding. PJM should fix the FTR/ARR design and then should let the market work to return congestion to load and to let FTR values reflect actual congestion.

Load should never be required to subsidize payments to FTR holders, regardless of the reason.[216] The FERC order of September 15, 2016, introduced a subsidy to FTR holders at the expense of ARR holders.[217] The order requires PJM to ignore balancing congestion when calculating total congestion dollars available to fund FTRs. As a result, balancing congestion and M2M payments are assigned to load, rather than to FTR holders, as of the 2017/2018 planning period. When combined with the direct assignment of both surplus day-ahead congestion and surplus FTR auction revenues to FTR holders, the Commission's

216 Such subsidies have been suggested repeatedly. See FERC Dockets Nos. EL13-47-000 and EL12-19-000.
217 See 156 FERC ¶ 61,180 (2016), *reh'g denied*, 156 FERC ¶ 61,093 (2017).

order shifted substantial revenue from load to the holders of FTRs and further reduced the offset to congestion payments by load. This approach ignores the fact that load pays both day-ahead and balancing congestion, and that congestion is defined, in an accounting sense, to equal the sum of day-ahead and balancing congestion. Eliminating balancing congestion from the FTR revenue calculation requires load to pay twice for congestion. Load pays total congestion and pays negative balancing congestion again. The fundamental reasons that there has been a significant and persistent difference between day-ahead and balancing congestion include inadequate transmission modeling in the FTR auction and the role of UTCs in taking advantage of these modeling differences and creating negative balancing congestion. There is no reason to impose these costs on load.

These changes were made in order to increase the payout to holders of FTRs who are not loads. Increasing the payout to FTR holders at the expense of the load is not a supportable market objective. PJM should implement an FTR design that calculates and assigns congestion rights to load rather than continuing to modify the current, fundamentally flawed, design.

Load was made significantly worse off as a result of the changes made to the FTR/ARR process by PJM based on the FERC order of September 15, 2016. ARR revenues were significantly reduced for the 2017/2018 FTR Auction, the first auction under the new rules. ARRs and self scheduled FTRs offset only 49.5 percent of total congestion costs for the 2017/2018 planning period rather than the 58.0 percent offset that would have occurred under the prior rules, a difference of $101.4 million.

A subsequent rule change was implemented that modified the allocation of surplus auction revenue to load. Beginning with the 2018/2019 planning period, surplus day-ahead congestion and surplus FTR auction revenue are assigned to FTR holders only up total target allocations, and then distributed to ARR holders.[218] ARR holders will only be allocated this surplus after full funding of FTRs is accomplished. While this rule change increased the level of congestion revenues returned to load, the rules do not recognize ARR holders' rights to all congestion revenue, and only improves congestion payouts to load when there is a surplus. There was no surplus for the 2020/2021 or 2021/2022 planning years. With this rule in effect for the 2021/2022 planning period, ARRs and self scheduled FTRs offset 31.5 percent of total congestion. Load has been underpaid congestion revenues by $3.8 billion from the 2011/2012 planning period through the first ten months of the 2022/2023 planning period. The cumulative offset for that period was 69.0 percent of total congestion.

The complex process related to what is termed the overallocation of Stage 1A ARRs is entirely an artificial result of reliance on the contract path model in the assignment of FTRs. For example, there is a reason that transmission is not built to address the Stage 1A overallocation issue. The Stage 1A overallocation issue is a fiction based on the use of outdated and irrelevant generation to load contract paths to assign Stage 1A rights that have nothing to do with actual power flows.

PJM proposed, and on March 11, 2022, FERC accepted, to increase Stage 1A ARR allocations from 50 percent of Network Service Base Load (NSBL) to 60 percent of Network Service Peak Load (NSPL) ("Stage 1A Proposal").[219] NSBL is a network service customer's contribution to the lowest daily zonal peak load in the prior twelve month period, and NSPL is a network service customer's contribution to the highest daily zonal peak load in the prior twelve month period. While PJM's proposal will increase Stage 1A rights, this will come at the cost of Stage 1B and Stage 2 ARR allocations. More importantly, PJM's proposal will not improve the alignment of congestion property rights to load, but will exacerbate the current misalignment.

Proposed Design

To address the issues with the current contract path based ARR/FTR market design, the MMU recommends that the current design be replaced with a design in which the rights to actual congestion paid are assigned directly to the load that paid that congestion by node. The assigned right would be the actual difference between load payments, both day-ahead and balancing, and revenues paid to the generation used to serve that load. The load could

218 163 FERC ¶ 61,165 (2018).

219 See 178 FERC ¶ 61,170.

retain the right to the network congestion or sell the right through auctions. The correct assignment of congestion revenues to load is fully consistent with retaining FTR auctions for the sale by ARR holders of their congestion revenue rights.

With a network assignment of actual congestion, there would be no cross subsidies among rights holders and no over or under allocation of rights relative to actual network market solutions. There would be no revenue shortfalls as congestion payments equal congestion collected. The risk of default would be isolated to the buyer and seller of the right, and any default would not be socialized to other right holders. In the case of a defaulting buyer, the rights to the congestion revenues would revert to the load. There would be no risk of a network right flipping in value from positive to negative, because congestion is always the positive difference between what load pays for energy, and generation is paid for energy as a result of transmission constraints.

The MMU proposal requires the calculation of constraint specific congestion and the calculation of that specific constraint's congestion related charges to each physical load bus downstream of that constraint. Under the MMU proposal, the constraint specific congestion calculated by hour, from both the day-ahead and balancing market would be paid directly to the physical load as a credit against the associated load serving entity's (LSE) energy bill. This right to the congestion is defined as the congestion revenue right (CRR) that belongs to the physical load at a defined bus, zone or aggregate. The LSE could choose to sell all or a portion of the CRR through auctions.

A CRR is the right to actual, realized network related congestion that is paid by physical load at a specific bus, zone or aggregate. Under the MMU proposal a bus, zone or aggregate specific CRR could be sold as a defined share of the actual congestion. For example, an LSE could sell 50 percent of its congestion revenue right for the planning period to a third party. The third party buyer would then be entitled to 50 percent of the congestion that will be credited to that specific bus, zone or aggregate for the planning period. The remaining 50 percent of the congestion credit for the specified bus, zone or aggregate would be paid to the LSE along with auction clearing price for the 50 percent of CRR that was sold to the third party. Depending on actual congestion, an LSE selling its congestion revenue rights could be better or worse off than if it retained its rights.

Under the MMU proposal, the LSE would be able to set reservation prices in the auction for the sale of portions or all of its CRR. Third parties would have an opportunity to bid for the offered portions of the CRR, and the market for the congestion revenue associated with the specified bus, zone or aggregate would clear at a price. If the reservation price of an identified portion of the offered CRR was not met at the clearing price, that portion of the offered CRR would remain with the load. Auctions could be annual and/or monthly.

Under the MMU proposal, point to point rights (FTRs) could exist as a separate, self-funded hedging product based on simultaneously feasible prevailing and counter flows in a PJM managed network based auction. The only supply and the only source of revenues in the point to point market for prevailing flow FTRs would be counter flow offers and direct payments for specific rights.

Recommendations

In order to perform its role in PJM market design, the MMU evaluates existing and proposed PJM Market Rules and the design of the PJM Markets.[1] The MMU initiates and proposes changes to the design of the markets and the PJM Market Rules in stakeholder and regulatory proceedings.[2] In support of this function, the MMU engages in discussions with stakeholders, State Commissions, PJM management, and the PJM Board; participates in PJM stakeholder meetings and working groups regarding market design matters; publishes proposals, reports and studies on market design issues; and makes filings with the Commission on market design issues.[3] The MMU also recommends changes to the PJM Market Rules to the staff of the Commission's Office of Energy Market Regulation, State Commissions, and the PJM Board.[4] The MMU may provide in its annual, quarterly and other reports "recommendations regarding any matter within its purview."[5]

Priority rankings are relative. The creation of rankings recognizes that there are limited resources available to address market issues and that problems must be ranked in order to determine the order in which to address them. It does not mean that all the problems should not be addressed. Priority rankings are dynamic and as new issues are identified, priority rankings will change. The rankings reflect a number of factors including the significance of the issue for efficient markets, the difficulty of completion and the degree to which items are already in progress. A low ranking does not necessarily mean that an issue is not important, but could mean that the issue would be easy to resolve.

There are three priority rankings: High, Medium and Low. High priority indicates that the recommendation requires action because it addresses a market design issue that creates significant market inefficiencies and/or long lasting negative market effects. Medium priority indicates that the recommendation addresses a market design issue that creates intermediate market inefficiencies and/or near term negative market effects. Low priority indicates that the recommendation addresses a market design issue that creates smaller market inefficiencies and/or more limited market effects or that it could be easily resolved.

1 OATT Attachment M § IV.D.
2 *Id.*
3 *Id.*
4 *Id.*
5 OATT Attachment M § VI.A.

The MMU also tracks PJM's progress in addressing these recommendations. The MMU recognizes that part of the process of addressing recommendations may include discussions in the stakeholder process, FERC decisions and court decisions and those elements are included in the tracking. The MMU recognizes that PJM does not have the unilateral authority to implement changes to the tariff but PJM has a significant role in the issues PJM focuses on, in proposed changes to the PJM manuals, and in the recommendations PJM makes to the stakeholders and to FERC. Each recommendation includes a status. The status categories are:

- **Adopted:** PJM has implemented the recommendation made by the MMU.
- **Partially adopted:** PJM has implemented part of the recommendation made by the MMU.
- **Not adopted:** PJM does not plan to implement the recommendation made by the MMU, or has not yet implemented any part of the recommendation made by the MMU. Where the subject of the recommendation is pending stakeholder, FERC, or court action, that status is noted.
- **Withdrawn:** The MMU no longer makes the recommendation because it has become irrelevant or because it has been replaced by another recommendation.

New Recommendations

Consistent with its core function to "[e]valuate existing and proposed market rules, tariff provisions and market design elements and recommend proposed rule and tariff changes," the MMU recommends specific enhancements to existing market rules and implementation of new rules that are required for competitive results in PJM markets and for continued improvements in the functioning of PJM markets.[6]

In this *2023 Quarterly State of the Market Report for PJM: January through March*, the MMU includes four new recommendations.

New Recommendation from Section 6, Demand Response

- The MMU recommends that PJM report the response of demand capacity resources to dispatch by PJM as the actual change in load rather than simply the difference between the amount of capacity purchased by the customer and the actual metered load. The current approach significantly overstates the response to PJM dispatch. (Priority: High. New recommendation. Status: Not adopted.)

New Recommendations from Section 10, Ancillary Services

- The MMU recommends that the two signal regulation market design be replaced with a one signal regulation market design. (Priority: Medium. New recommendation. Status: Not adopted.)
- The MMU recommends that black start planning and coordination be on a regional basis and not on a zonal basis and that the costs of black start service be shared equally across the region. (Priority: Medium. New recommendation. Status: Not adopted.)

6 18 CFR § 35.28(g)(3)(ii)(A); see also OATT Attachment M § IV.D.

New Recommendation from Section 12, Generation and Transmission Planning

- Given the significance of data to market participants and regulators, the MMU recommends that all queue data and supplemental, network and baseline project data, including projected in service dates and estimated and final costs, be regularly updated with accurate and verifiable data. (Priority: High. New recommendation. Not adopted.)

Complete List of Current MMU Recommendations

The recommendations are explained in each section of the report.

Section 3, Energy Market

Market Power

- The MMU recommends that the market rules explicitly require that offers in the energy market be competitive, where competitive is defined to be the short run marginal cost of the units. The short run marginal cost should reflect opportunity cost when appropriate. The MMU recommends that the level of incremental costs includable in cost-based offers not exceed the short run marginal cost of the unit. (Priority: Medium. First reported 2009. Status: Not adopted.)

Fuel Cost Policies

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

follow their approved fuel cost policy. (Priority: Medium. First reported 2020. Status: Not adopted.)

Cost-Based Offers

- The MMU recommends that Manual 15 (Cost Development Guidelines) be replaced or updated with a straightforward description of the components of cost-based offers and the mathematically correct calculation of cost-based offers. (Priority: Medium. First reported 2016. Status: Partially adopted Q1 2022.)[7]
- The MMU recommends removal of all use of FERC System of Accounts in the Cost Development Guidelines. (Priority: Medium. First reported 2016. Status: Not adopted.)
- The MMU recommends the removal of all use of cyclic starting and peaking factors from the Cost Development Guidelines. (Priority: Medium. First reported 2016. Status: Not adopted.)
- The MMU recommends the removal of all labor costs from the Cost Development Guidelines. (Priority: Medium. First reported 2016. Status: Adopted 2022.)
- The MMU recommends the removal of all maintenance costs from the Cost Development Guidelines. (Priority: Medium. First reported 2019. Status: Not adopted.)
- The MMU recommends that market participants be required to document the amount and cost of consumables used when operating in order to verify that the total operating cost is consistent with the total quantity used and the unit characteristics. (Priority: Medium. First reported 2020. Status: Adopted 2023.)
- The MMU recommends, given that maintenance costs are currently allowed in cost-based offers, that market participants be permitted to include only variable maintenance costs, linked to verifiable operational events and that can be supported by clear and unambiguous documentation of the operational data (e.g. run hours, MWh, MMBtu) that support the maintenance cycle of the equipment being serviced/replaced. (Priority: Medium. First reported 2020. Status: Not adopted.)
- The MMU recommends explicitly accounting for soak costs and changing the definition of the start heat input for combined cycles to include only the amount of fuel used from first fire to the first breaker close in the Cost Development Guidelines. (Priority: Medium. First reported 2016. Status: Partially Adopted.)
- The MMU recommends that soak costs, soak time and the MWh produced during soaking be modeled separately. This will ensure that the time required for units to reach a dispatchable level is known and used in the unit commitment process instead of only being communicated verbally between dispatchers and generators. Separating soak costs from start costs and modeling the MWh produced during soaking allows for a better representation of the costs because it eliminates the need to simply assume the price paid for those MWh. (Priority: Medium. First reported 2022. Status: Not Adopted.)
- The MMU recommends the removal of nuclear fuel and nonfuel operations and maintenance costs that are not short run marginal costs from the Cost Development Guidelines. (Priority: Medium. First reported 2016. Status: Not adopted.)
- The MMU recommends revising the pumped hydro fuel cost calculation to include day-ahead and real-time power purchases. (Priority: Low. First reported 2016. Status: Not adopted.)

Market Power: TPS Test and Offer Capping

- The MMU recommends that the rules governing the application of the TPS test be clarified and documented. The TPS test application in the day-ahead energy market is not documented. (Priority: High. First reported 2015. Status: Partially adopted.)[8]
- The MMU recommends that PJM modify the process of applying the TPS test in the day-ahead energy market to ensure that all local markets created by binding constraints are tested for market power and to ensure that market sellers with market power are appropriately mitigated to their

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

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

competitive offers. (Priority: High. First reported Q1 2022. Status: Not adopted.)

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

Offer Behavior

- The MMU recommends that resources not be allowed to violate the ICAP must offer requirement. The MMU recommends that PJM enforce the ICAP must offer requirement by assigning a forced outage to any unit that is derated in the energy market below its committed ICAP without an outage that reflects the derate. (Priority: Medium. First reported 2020. Status: Not adopted.)
- The MMU recommends that storage and intermittent resources be subject to an enforceable ICAP must offer rule that reflects the limitations of these resources. (Priority: Medium. First reported 2020. Status: Not adopted.)
- The MMU recommends that capacity resources not be allowed to offer any portion of their capacity market obligation as maximum emergency energy. (Priority: Medium. First reported 2012. Status: Not adopted.)
- The MMU recommends that PJM integrate all the outage reporting tools in order to enforce the ICAP must offer requirement, ensure that outages are reported correctly and eliminate reporting inconsistencies. Generators currently submit availability in three different tools that are not integrated, Markets Gateway, eDART and eGADS. (Priority: Medium. First reported 2022. Status: Not adopted.)
- The MMU recommends that gas generators be required to check with pipelines throughout the operating day to confirm that nominations are accepted beyond the NAESB deadlines, and that gas generators be required to place their units on forced outage until the time that pipelines allow nominations to consume gas at a unit. (Priority: Medium. First reported Q1 2022. Status: Not adopted.)

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

Capacity Resources

- The MMU recommends that capacity resources be held to the OEM operating parameters of the capacity market CONE reference resource for performance assessment and energy uplift payments and that this standard be applied to all technologies on a uniform basis. (Priority: Medium. First reported 2015. Status: Not adopted.)
- The MMU recommends that the parameters which determine nonperformance charges and the amounts of uplift payments should reflect the flexibility goals of the capacity market design. The operational parameters used by generation owners to indicate to PJM operators what a unit is capable of during the operating day should not determine capacity resource performance assessment or uplift payments. (Priority: Medium. First reported 2015. Status: Partially adopted.)[10]
- The MMU recommends that PJM clearly define the business rules that apply to the unit specific parameter adjustment process, including PJM's implementation of the tariff rules in the PJM manuals to ensure market sellers know the requirements for their resources. (Priority: Low. First reported 2018. Status: Not adopted.)
- The MMU recommends that PJM update the tariff to clarify that all generation resources are subject to unit specific parameter limits on their cost-based offers using the same standard and process as capacity resources. (Priority: Medium. First reported 2018. Status: Not adopted.)
- The MMU recommends that resources not be paid the daily capacity payment when unable to operate to their unit specific parameter limits. (Priority: Medium. First reported 2018. Status: Not adopted.)
- The MMU recommends that PJM not approve temporary exceptions that are based on pipeline tariff terms that are not enforced at the time, or are based on inferior transportation service procured by the generator. (Priority: Medium. First reported 2019. Status: Not adopted.)
- The MMU recommends that PJM require generators that violate their approved turn down ratio (by either using the fixed gen option or increasing their economic minimum) to use the temporary parameter exception process that requires market sellers to demonstrate that the request is based on a physical and actual constraint. (Priority: Medium. First reported 2021. Status: Not adopted.)
- The MMU recommends: that gas generators be required to confirm, regularly during the operating day, that they can obtain gas if requested to operate at their economic maximum level; that gas generators provide that information to PJM during the operating day; and that gas generators be required to be on forced outage if they cannot obtain gas during the operating day to meet their must offer requirement as a result of pipeline restrictions, and they do not have backup fuel. As part of this, the MMU recommends that PJM collect data on each individual generator's fuel supply arrangements at least annually or when such arrangements change, and analyze the associated locational and regional risks to reliability. (Priority: Medium. First reported Q1 2022. Status: Not adopted.)
- The MMU recommends, if the capacity market seller offer cap were to be calculated using the historical average balancing ratio, that PJM not include the balancing ratios calculated for localized Performance Assessment Intervals (PAIs), and only include those events that trigger emergencies at a defined zonal or higher level. (Priority: Medium. First reported 2018. Status: Not adopted.)

Accurate System Modeling

- The MMU recommends that PJM explicitly state its policy on the use of transmission penalty factors including: the level of the penalty factors; the triggers for the use of the penalty factors; the appropriate line ratings to trigger the use of penalty factors; the allowed duration of the violation and when the transmission penalty factors will be used to set the shadow price. The MMU recommends that PJM end the practice of discretionary reductions in transmission line ratings modeled in the market clearing and included in LMP. (Priority: Medium. First reported 2015. Status: Partially adopted 2020.)[11]

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

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

- The MMU recommends that PJM routinely review all transmission facility ratings and any changes to those ratings to ensure that the normal, emergency and load dump ratings used in modeling the transmission system are accurate and reflect standard ratings practice. (Priority: Low. First reported 2013. Status: Not adopted.)
- The MMU recommends that PJM not use closed loop interface or surrogate constraints to artificially override nodal prices based on fundamental LMP logic in order to: accommodate rather than resolve the inadequacies of the demand side resource capacity product; address the inability of the power flow model to incorporate the need for reactive power; accommodate rather than resolve the flaws in PJM's approach to scarcity pricing; or for any other reason. (Priority: Medium. First reported 2013. Status: Not adopted.)
- The MMU recommends that PJM update the outage impact studies, the reliability analyses used in RPM for capacity deliverability, and the reliability analyses used in RTEP for transmission upgrades to be consistent with the more conservative emergency operations (post contingency load dump limit exceedance analysis) in the energy market that were implemented in June 2013.[12] (Priority: Low. First reported 2013. Status: Not adopted.)
- The MMU recommends that PJM include in the tariff or appropriate manual an explanation of the initial creation of hubs, the process for modifying hub definitions and a description of how hub definitions have changed.[13] [14] (Priority: Low. First reported 2013. Status: Not adopted.)
- The MMU recommends that all buses with a net withdrawal be treated as load for purposes of calculating load and load-weighted LMP, even if the MW are settled to the generator. The MMU recommends that during hours when a load bus shows a net injection, the energy injection be treated as generation, not negative load, for purposes of calculating generation and load-weighted LMP, even if the injection MW are settled to the load serving entity. (Priority: Low. First reported 2013. Status: Not adopted.)
- The MMU recommends that PJM identify and collect data on available behind the meter generation resources, including nodal location information and relevant operating parameters. (Priority: Low. First reported 2013. Status: Partially adopted.)
- The MMU recommends that PJM document how LMPs are calculated when demand response is marginal. (Priority: Low. First reported 2014. Status: Not adopted.)
- The MMU recommends that PJM not allow nuclear generators which do not respond to prices or which only respond to manual instructions from the operator to set the LMPs in the real-time market. (Priority: Low. First reported 2016. Status: Not adopted.)
- The MMU recommends that PJM increase the coordination of outage and operational restrictions data submitted by market participants via eDART/eGADs and offer data submitted via Markets Gateway. (Priority: Low. First reported 2017. Status: Not adopted.)
- The MMU recommends that PJM model generators' operating transitions, including soak time for units with a steam turbine, configuration transitions for combined cycles, and peak operating modes. (Priority: Medium. First reported 2019. Status: Not adopted.)
- The MMU recommends that PJM clarify, modify and document its process for dispatching reserves and energy when SCED indicates that supply is less than total demand including forecasted load and reserve requirements. The modifications should define: a SCED process to economically convert reserves to energy; a process for the recall of energy from capacity resources; and the minimum level of synchronized reserves that would trigger load shedding. (Priority: Medium. First reported 2020. Status: Not adopted.)
- The MMU recommends that PJM stop capping the system marginal price in RT SCED and instead limit the sum of violated reserve constraint shadow prices used in LPC to $1,700 per MWh. (Priority: Medium. First reported Q1, 2021. Status: Not adopted.)

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

13 According to minutes from the first meeting of the Energy Market Committee (EMC) on January 28, 1998, the EMC unanimously agreed to be responsible for approving additions, deletions and changes to the hub definitions to be published and modeled by PJM. Since the EMC has become the Market Implementation Committee (MIC), the MIC now appears to be responsible for such changes.

14 There is currently no PJM documentation in the tariff or manuals explaining how hubs are created and how their definitions are changed. The general definition of a hub can be found in the PJM.com Glossary <http://www.pjm.com/Glossary.aspx>.

- The MMU recommends that PJM adjust the ORDCs during spin events to reduce the reserve requirement for synchronized and primary reserves by the amount of the reserves deployed. (Priority: Medium. First reported 2021. Status: Not adopted.)

Transparency

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

Virtual Bids and Offers

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

15 Fuel type is reported by offer schedule, but it can be inaccurate on an hourly basis.
16 The PJM Market Rules clarify that shortage case approval will be based on RT SCED, but does not address RT SCED case choice or load bias.

Section 4, Energy Uplift

- The MMU recommends that uplift be paid only based on operating parameters that reflect the flexibility of the benchmark new entrant unit (CONE unit) in the PJM Capacity Market. (Priority: High. First reported 2018. Status: Not adopted.)
- The MMU recommends that PJM not pay uplift to units not following dispatch, including uplift related to fast start pricing, and require refunds where it has made such payments. This includes units whose offers are flagged for fixed generation in Markets Gateway because such units are not dispatchable. (Priority: Medium. First reported 2018. Status: Not adopted.)
- The MMU recommends that PJM pay uplift based on the offer at the lower of the actual unit output or the dispatch signal MW. (Priority: Medium. First reported 2018. Status: Not adopted.)
- The MMU recommends eliminating intraday segments from the calculation of uplift payments and returning to calculating the need for uplift based on the entire 24 hour operating day. (Priority: High. First reported 2018. Status: Not adopted.)
- The MMU recommends the elimination of day-ahead uplift to ensure that units receive an energy uplift payment based on their real-time output and not their day-ahead scheduled output. (Priority: Medium. First reported 2013. Status: Not adopted.)
- The MMU recommends that units not be paid lost opportunity cost uplift credits when PJM directs a unit to reduce output based on a transmission constraint or other reliability issue. There is no lost opportunity because the unit is required to reduce for the reliability of the unit and the system. (Priority: High. First reported 2021. Status: Not adopted.)
- The MMU recommends reincorporating the use of net regulation revenues as an offset in the calculation of balancing generator credits. (Priority: Medium. First reported 2009. Status: Not adopted.)
- The MMU recommends that self scheduled units not be paid energy uplift credits for their startup cost when the units are scheduled by PJM to start

before the self scheduled hours. (Priority: Low. First reported 2013. Status: Not adopted.)

- The MMU recommends three modifications to the energy lost opportunity cost calculations:
  - The MMU recommends calculating LOC based on 24 hour daily periods for combustion turbines and diesels scheduled in the day-ahead energy market, but not committed in real time. (Priority: Medium. First reported 2014. Status: Not adopted.)
  - The MMU recommends that units scheduled in the day-ahead energy market and not committed in real time should be compensated for LOC based on their real-time desired and achievable output, not their scheduled day-ahead output. (Priority: Medium. First reported 2015. Status: Not adopted.)
  - The MMU recommends that only flexible fast start units (startup plus notification times of 10 minutes or less) and units with short minimum run times (one hour or less) be eligible by default for the LOC compensation to units scheduled in the day-ahead energy market and not committed in real time. Other units should be eligible for LOC compensation only if PJM explicitly cancels their day-ahead commitment. (Priority: Medium. First reported 2015. Status: Not adopted.)
- The MMU recommends that up to congestion (UTC) transactions be required to pay energy uplift charges for both the injection and the withdrawal sides of the UTC. (Priority: High. First reported 2011. Status: Partially adopted.)
- The MMU recommends allocating the energy uplift credits paid to units scheduled by PJM as must run in the day-ahead energy market for reasons other than voltage/reactive or black start services as a reliability charge to real-time load, real-time exports and real-time wheels. (Priority: Medium. First reported 2014. Status: Not adopted. Stakeholder process.)
- The MMU recommends that the total cost of providing reactive support be categorized and allocated as reactive services. Reactive services credits should be calculated consistent with the balancing generator credit calculation. (Priority: Medium. First reported 2012. Status: Not adopted. Stakeholder process.)
- The MMU recommends including real-time exports and real-time wheels in the allocation of the cost of providing reactive support to the 500 kV system or above, in addition to real-time load. (Priority: Low. First reported 2013. Status: Not adopted.)
- The MMU recommends modifications to the calculation of lost opportunity costs credits paid to wind units. The lost opportunity costs credits paid to wind units should be based on the lesser of the desired output, the estimated output based on actual wind conditions and the capacity interconnection rights (CIRs). The MMU recommends that PJM allow wind units to request CIRs that reflect the maximum output wind units want to inject into the transmission system at any time. (Priority: Low. First reported 2012. Status: Partially adopted.)
- The MMU recommends that PJM clearly identify and classify all reasons for incurring uplift in the day-ahead and the real-time energy markets and the associated uplift charges in order to make all market participants aware of the reasons for these costs and to help ensure a long term solution to the issue of how to allocate the costs of uplift. (Priority: Medium. First reported 2011. Status: Partially adopted.)
- The MMU recommends that PJM revise the current uplift confidentiality rules in order to allow the disclosure of complete information about the level of uplift by unit and the detailed reasons for the level of uplift credits by unit in the PJM region. (Priority: High. First reported 2013. Status: Partially adopted.)[17]
- The MMU recommends that PJM eliminate the exemption for CTs and diesels from the requirement to follow dispatch in order to receive uplift. The performance of these resources should be evaluated in a manner consistent with all other resources (Priority: Medium. First reported 2018. Status: Adopted 2022.)

17 On September 7, 2018, PJM made a compliance filing for FERC Order No. 844 to publish unit specific uplift credits. The compliance filing was accepted by FERC on June 21, 2019. 166 FERC ¶ 61,210 (2019). PJM began posting unit specific uplift reports on May 1, 2019. 167 FERC ¶ 61,280 (2019).

Section 5, Capacity Market

Definition of Capacity

- The MMU recommends elimination of the key remaining components of the CP model because they interfere with competitive outcomes in the capacity market and create unnecessary complexity and risk. (Priority: High. First reported Q3, 2022. Status: Not adopted.)
- The MMU recommends the enforcement of a consistent definition of capacity resources. The MMU recommends that the requirement to be a physical resource be enforced and enhanced. The requirement to be a physical resource should apply at the time of auctions and should also constitute a commitment to be physical in the relevant delivery year. The requirement to be a physical resource should be applied to all resource types, including planned generation, demand resources and imports.[18] [19] (Priority: High. First reported 2013. Status: Not adopted.)
- The MMU recommends that DR providers be required to have a signed contract with specific customers for specific facilities for specific levels of DR at least six months prior to any capacity auction in which the DR is offered. (Priority: High. First reported 2016. Status: Not adopted.)
- The MMU recommends that Energy Efficiency Resources (EE) not be included in the capacity market because PJM's load forecasts now account for EE, unlike the situation when EE was first added to the capacity market.[20] (Priority: Medium. First reported 2016. Status: Not adopted.)
- The MMU recommends that intermittent resources, including storage, not be permitted to offer capacity MW based on energy deliveries that exceed their defined deliverability rights (CIRs). Only energy output for such resources below the designated CIR/deliverability level should be recognized in the definition of derated capacity (e.g. ELCC). Correctly defined derating factors will be lower than the CIRs required to meet those derating factors. (Priority: High. First reported 2021. Status: Not adopted.)
- The MMU recommends that PJM require all market participants to meet their deliverability requirements under the same rules. PJM should end the practice of giving away winter CIRs that appear to exist because other resources paid for the supporting network upgrades. (Priority: High. First reported 2017. Status: Not adopted.)[21]
- The MMU recommends that the must offer rule in the capacity market apply to all capacity resources. There is no reason to exempt intermittent and capacity storage resources, including hydro, and demand resources and energy efficiency resources from the must offer requirement. The same rules should apply to all capacity resources. (Priority: High. First reported 2021. Status: Not adopted.)

Market Design and Parameters

- The MMU recommends that PJM reevaluate the shape of the VRR curve. The shape of the VRR curve directly results in load paying substantially more for capacity than load would pay with a vertical demand curve. More specifically, the MMU recommends that the VRR curve be rotated half way towards the vertical demand curve at the reliability requirement for the current Quadrennial Review. (Priority: High. First reported 2021. Status: Partially adopted.)
- The MMU recommends that the maximum price on the VRR curve be defined as net CONE. (Priority: Medium. First reported 2019. Status: Not adopted.)
- The MMU recommends that the test for determining modeled Locational Deliverability Areas (LDAs) in RPM be redefined. A detailed reliability analysis of all at risk units should be included in the redefined model. (Priority: Medium. First reported 2013. Status: Not adopted.)
- The MMU recommends that PJM clear the capacity market based on nodal capacity resource locations and the characteristics of the transmission system consistent with the actual electrical facts of the grid. Absent a fully nodal capacity market clearing process, the MMU recommends that PJM

18 See also Comments of the Independent Market Monitor for PJM, Docket No. ER14-503-000 (December 20, 2013).
19 See "Analysis of Replacement Capacity for RPM Commitments: June 1, 2007 to June 1, 2019," <http://www.monitoringanalytics.com/reports/Reports/2019/IMM_Analysis_of_Replacement_Capacity_for_RPM_Commitments_June_1_2007_to_June_1_2019_20190913.pdf> (September 13, 2019).
20 "PJM Manual 19: Load Forecasting and Analysis," § 3.2 Development of the Forecast, Rev. 35 (Dec. 31, 2021).
21 This recommendation was first made in the 2020/2021 BRA report in 2017. See the "Analysis of the 2020/2021 RPM Base Residual Auction," <http://www.monitoringanalytics.com/reports/Reports/2017/IMM_Analysis_of_the_20202021_RPM_BRA_20171117.pdf> (November 11, 2017).

use a non-nested model with all LDAs modeled including VRR curves for all LDAs. Each LDA requirement should be met with the capacity resources located within the LDA and exchanges from neighboring LDAs up to the transmission limit. LDAs should be allowed to price separate if that is the result of the LDA supply curves and the transmission constraints between LDAs. (Priority: Medium. First reported 2017. Status: Not adopted.)

- The MMU recommends the use of a forward looking energy and ancillary services (E&AS) net revenue offset rather than the backward looking E&AS net revenue offset currently in the tariff. Forward prices for energy prices and fuel costs are a better guide to market expectations of net revenues than an average of the actual net revenues for the last three years. (Priority: High. First reported 2014. Status: Not adopted.)[22]
- The MMU recommends that PJM reduce the number of incremental auctions to a single incremental auction held three months prior to the start of the delivery year and reevaluate the triggers for holding conditional incremental auctions. (Priority: Medium. First reported 2013. Status: Not adopted.)
- The MMU recommends that PJM not sell back any capacity in any IA procured in a BRA. If PJM continues to sell back capacity, the MMU recommends that PJM offer to sell back capacity in incremental auctions only at the BRA clearing price for the relevant delivery year. (Priority: Medium. First reported 2017. Status: Not adopted.)
- The MMU recommends changing the RPM solution method to explicitly incorporate the cost of uplift (make whole) payments in the objective function. (Priority: Medium. First reported 2014. Status: Not adopted.)
- The MMU recommends that the Fixed Resource Requirement (FRR) rules, including obligations and performance requirements, be revised and updated to ensure that the rules reflect current market realities and that FRR entities do not unfairly take advantage of those customers paying for capacity in the PJM capacity market. (Priority: Medium. First reported 2019. Status: Not adopted.)

22 This recommendation was first made during the Quadrennial Review in 2014, including the PJM Capacity Senior Task Force (CSTF), the MRC and the MC. <https://www.pjm.com/committees-and-groups/closed-groups/cstf>.

- The MMU recommends that the value of CTRs should be defined by the total MW cleared in the capacity market, the internal MW cleared and the imported MW cleared, and not redefined later prior to the delivery year. (Priority: Medium. First reported 2021. Status: Not adopted.)
- The MMU recommends that the market clearing results be used in settlements rather than the reallocation process currently used, or that the process of modifying the obligations to pay for capacity be reviewed. (Priority: Medium. First reported 2021. Status: Not adopted.)
- The MMU recommends that PJM improve the clarity and transparency of its CETL calculations. The MMU also recommends that CETL for capacity imports into PJM be based on the ability to import capacity only where PJM capacity exists and where that capacity has a must offer requirement in the PJM Capacity Market. (Priority: Medium. First reported 2021. Status: Partially adopted 2022.)
- The MMU recommends that the value of CTRs be defined by the total MW cleared in the capacity market, the internal MW cleared and the imported MW cleared, and not redefined later prior to the delivery year. Capacity Transfer Rights (CTRs) are used to return capacity market congestion revenues to load, but the CTRs that result from market clearing prices and quantities are not included in final settlements for individual LDAs. MMU also recommends that the market clearing results be used in settlements rather than the reallocation process currently used or that the process of modifying the obligations to pay for capacity be reviewed. (Priority: High. First reported 2022. Status: Not adopted.)[23]

Offer Caps, Offer Floors, and Must Offer

- The MMU recommends using the lower of the cost or price-based energy market offer to calculate energy costs in the calculation of the historical net revenues which are an offset to gross ACR in the calculation of unit specific capacity resource offer caps based on net ACR. (Priority: Medium. First reported 2021. Status: Not adopted.)

23 This recommendation first made in the 2023/2024 BRA report in 2022. See "Analysis of the 2023/2024 RPM Base Residual Auction Revised," <http://www.monitoringanalytics.com/reports/Reports/2022/IMM_Analysis_of_the_20232024_RPM_Base_Residual_Auction_20221028.pdf> (October 28, 2022).

- The MMU recommends use of the Sustainable Market Rule (SMR) in order to protect competition in the capacity market from nonmarket revenues.[24] (Priority: High. First reported 2016. Status: Not adopted.)
- The MMU recommends that, as part of the MOPR unit specific standard of review, all projects be required to use the same basic modeling assumptions. That is the only way to ensure that projects compete on the basis of actual costs rather than on the basis of modeling assumptions.[25] (Priority: High. First reported 2013. Status: Not adopted.)
- The MMU recommends that modifications to existing resources be subject to market power related offer caps or MOPR offer floors and not be treated as new resources and therefore exempt. (Priority: Low. First reported 2012. Status: Not adopted.)
- The MMU recommends that the RPM market power mitigation rule be modified to apply offer caps in all cases when the three pivotal supplier test is failed and the sell offer is greater than the offer cap. This will ensure that market power does not result in an increase in uplift (make whole) payments for seasonal products. (Priority: Medium. First reported 2017. Status: Not adopted.)
- The MMU recommends that any combined seasonal resources be required to be in the same LDA and preferably at the same location, in order for the energy market and capacity market to remain synchronized and reliability metrics correctly calculated. (Priority: Medium. First reported 2021. Status: Not adopted.)
- The MMU recommends that the definition of avoidable costs in the tariff be corrected to be consistent with the economic definition. Avoidable costs are costs that are neither short run marginal costs, like fuel or consumables, nor fixed costs like depreciation and rate of return. Avoidable costs are the annual marginal costs of capacity and therefore the competitive offer level for capacity resources and therefore the market seller offer cap. Avoidable costs are the annual marginal costs of capacity whether a new resource or an existing resource. (Priority: Medium. First reported 2017. Status: Not adopted.)[26]
- The MMU recommends that capacity market sellers be required to explicitly request and support the use of minimum MW quantities (inflexible sell offer segments) and that the requests only be permitted for defined physical reasons. (Priority: Medium. First reported 2018. Status: Not adopted.)
- The MMU recommends that relatively small proposed increases in the capability of a Generation Capacity Resource be treated as an existing resource and subject to the corresponding market power mitigation rules and no longer be treated as planned and exempt from offer capping. (Priority: Medium. First reported 2012. Status: Not adopted.)[27]

Performance Incentive Requirements of RPM

- The MMU recommends that any unit not capable of supplying energy equal to its day-ahead must offer requirement (ICAP) be required to reflect an appropriate outage. (Priority: Medium. First reported 2009. Status: Not adopted.)
- The MMU recommends that retroactive replacement transactions associated with a failure to perform during a PAI not be allowed and that, more generally, retroactive replacement capacity transactions not be permitted. (Priority: Medium. First reported 2016. Status: Not adopted.)
- The MMU recommends that there be an explicit requirement that capacity resource offers in the day-ahead energy market be competitive, where competitive is defined to be the short run marginal cost of the units, including flexible operating parameters. (Priority: Low. First reported 2013. Status: Not adopted.)

24 Brief of the Independent Market Monitor for PJM, Docket No. EL16-49, ER18-1314-000,-001; EL18-178 (October 2, 2018).

25 See 143 FERC ¶ 61,090 (2013) ("We encourage PJM and its stakeholders to consider, for example, whether the unit-specific review process would be more effective if PJM requires the use of common modeling assumptions for establishing unit-specific offer floors while, at the same time, allowing sellers to provide support for objective, individual cost advantages. Moreover, we encourage PJM and its stakeholders to consider these modifications to the unit-specific review process together with possible enhancements to the calculation of Net CONE."); see also, Comments of the Independent Market Monitor for PJM, Docket No. ER13-535-001 (March 25, 2013); Complaint of the Independent Market Monitor for PJM v. Unnamed Participant, Docket No. EL12-63-000 (May 1, 2012); Motion for Clarification of the Independent Market Monitor for PJM, Docket No. ER11-2875-000, et al. (February 17, 2012); Protest of the Independent Market Monitor for PJM, Docket No. ER11-2875-002 (June 2, 2011); Comments of the Independent Market Monitor for PJM, Docket Nos. EL11-20 and ER11-2875 (March 4, 2011).

26 This recommendation was first made in the 2023/2024 BRA report in 2022. See "Analysis of the 2023/2024 RPM Base Residual Auction Revised," <http://www.monitoringanalytics.com/reports/Reports/2022/IMM_Analysis_of_the_20232024_RPM_Base_Residual_Auction_20221028.pdf> (October 28, 2022).

27 This recommendation was first made in the 2014/2015 BRA report in 2012. See "Analysis of the 2014/2015 RPM Base Residual Auction," <http://www.monitoringanalytics.com/reports/Reports/2012/Analysis_of_2014_2015_RPM_Base_Residual_Auction_20120409.pdf> (April 9, 2012).

- The MMU recommends that Capacity Performance resources be required to perform without excuses. Resources that do not perform should not be paid regardless of the reason for nonperformance. (Priority: High. First reported 2019. Status: Not adopted.)
- The MMU recommends that the market data posting rules be modified to allow the disclosure of expected performance, actual performance, shortfall and bonus MW during a PAI by area without the requirement that more than three market participants' data be aggregated for posting. (Priority: Low. First reported 2019. Status: Not adopted.)
- The MMU recommends that PJM require actual seasonal tests as part of the Summer/Winter Capability Testing rules, that the number of tests be limited, and that the ambient conditions under which the tests are performed be defined. (Priority: Medium. First reported Q1 2022. Status: Not adopted.)
- The MMU recommends that PJM select the time and day that a unit undergoes Net Capability Verification Testing, not the unit owner, and that this information not be communicated in advance to the unit owner. (Priority: Medium. First reported Q2 2022. Status: Not adopted.)

Capacity Imports and Exports

- The MMU recommends that all capacity imports be required to be deliverable to PJM load in an identified LDA, zonal or smaller, or explicit combinations of specific zones, e.g. MAAC, prior to the relevant delivery year to ensure that they are full substitutes for internal, physical capacity resources. Pseudo ties alone are not adequate to ensure deliverability to PJM load. (Priority: High. First reported 2016. Status: Not adopted.)
- The MMU recommends that all costs incurred as a result of a pseudo tied unit be borne by the unit itself and included as appropriate in unit offers in the capacity market. (Priority: High. First reported 2016. Status: Not adopted.)

Deactivations/Retirements

- The MMU recommends that the notification requirement for deactivations be extended from 90 days prior to the date of deactivation to 12 months prior to the date of deactivation and that PJM and the MMU be provided 60 days rather than 30 days to complete their reliability and market power analyses. (Priority: Low. First reported 2012. Status: Partially adopted.)
- The MMU recommends that units recover all and only the incremental costs, including incremental investment costs, required by the Part V reliability service (RMR service) that the unit owner would not have incurred if the unit owner had deactivated its unit as it proposed. Customers should bear no responsibility for paying previously incurred costs, including a return on or of prior investments. (Priority: Low. First reported 2010. Status: Not adopted.)
- The MMU recommends elimination of the cost of service recovery rate in OATT Section 119, that Part V reliability service (RMR) should be provided under the deactivation avoidable cost rate in Part V, and that the cap on investment under the avoidable cost rate option be eliminated. The MMU also recommends specific improvements to the DACR provisions. (Priority: Medium. First reported 2017. Status: Not adopted.)

Section 6, Demand Response

- The MMU recommends that PJM report the response of demand capacity resources to dispatch by PJM as the actual change in load rather than simply the difference between the amount of capacity purchased by the customer and the actual metered load. The current approach significantly overstates the response to PJM dispatch. (Priority: High. New recommendation. Status: Not adopted.)
- The MMU recommends, as a preferred alternative to including demand resources as supply in the capacity market, that demand resources be on the demand side of the markets, that customers be able to avoid capacity and energy charges by not using capacity and energy at their discretion, that customer payments be determined only by metered load, and that

PJM forecasts immediately incorporate the impacts of demand side behavior. (Priority: High. First reported 2014. Status: Not adopted.)

- The MMU recommends that the option to specify a minimum dispatch price (strike price) for demand resources be eliminated and that participating resources receive the hourly real-time LMP less any generation component of their retail rate. (Priority: Medium. First reported 2010. Status: Not adopted.)
- The MMU recommends that the maximum offer for demand resources be the same as the maximum offer for generation resources. (Priority: Medium. First reported 2013. Status: Not adopted.)
- The MMU recommends that the demand resources be treated as economic resources, responding to economic price signals like other capacity resources. The MMU recommends that demand resources not be treated as emergency resources, not trigger a PJM emergency and not trigger a Performance Assessment Interval. The MMU recommends that demand resources be available for every hour of the year. (Priority: High. First reported 2012. Status: Not adopted.)
- The MMU recommends that the Emergency Program Energy Only option be eliminated because the opportunity to receive the appropriate energy market incentive is already provided in the economic program. (Priority: Low. First reported 2010. Status: Not adopted.)
- The MMU recommends that, if demand resources remain in the capacity market, a daily energy market must offer requirement apply to demand resources, comparable to the rule applicable to generation capacity resources.[28] (Priority: High. First reported 2013. Status: Not adopted.)
- The MMU recommends that demand resources be required to provide their nodal location, comparable to generation resources. (Priority: High. First reported 2011. Status: Not adopted.)
- The MMU recommends that PJM require nodal dispatch of demand resources with no advance notice required or, if nodal location is not required, subzonal dispatch of demand resources with no advance notice required. The MMU recommends that, if PJM continues to use subzones for any purpose, PJM clearly define the role of subzones in the dispatch of demand response. (Priority: High. First reported 2015. Status: Not adopted.)
- The MMU recommends that PJM not remove any defined subzones and maintain a public record of all created and removed subzones. (Priority: Low. First reported 2016. Status: Not adopted.)
- The MMU recommends that PJM eliminate the measurement of compliance across zones within a compliance aggregation area (CAA). The multiple zone approach is less locational than the zonal and subzonal approach and creates larger mismatches between the locational need for the resources and the actual response. (Priority: High. First reported 2015. Status: Not adopted.)
- The MMU recommends that measurement and verification methods for demand resources be modified to reflect compliance more accurately. (Priority: Medium. First reported 2009. Status: Not adopted.)
- The MMU recommends that compliance rules be revised to include submittal of all necessary hourly load data, and that negative values be included when calculating event compliance across hours and registrations. (Priority: Medium. First reported 2012. Status: Not adopted.)
- The MMU recommends that PJM adopt the ISO-NE five-minute metering requirements in order to ensure that operators have the necessary information for reliability and that market payments to demand resources be calculated based on interval meter data at the site of the demand reductions.[29] (Priority: Medium. First reported 2013. Status: Not adopted.)
- The MMU recommends demand response event compliance be calculated on a five minute basis for all capacity performance resources and that the penalty structure reflect five minute compliance. (Priority: Medium. First reported 2013. Status: Partially adopted.)
- The MMU recommends that load management testing be initiated by PJM with limited warning to CSPs in order to more accurately represent the

28 See "Complaint and Motion to Consolidate of the Independent Market Monitor for PJM," Docket No. EL14-20-000 (January 27, 2014) at 1.

29 See ISO-NE Tariff, Section III, Market Rule 1, Appendix E1 and Appendix E2, "Demand Response," <http://www.iso-ne.com/regulatory/tariff/sect_3/mr1_append-e.pdf>. (Accessed October 17, 2017) ISO-NE requires that DR have an interval meter with five-minute data reported to the ISO and each behind the meter generator is required to have a separate interval meter. After June 1, 2017, demand response resources in ISO-NE must also be registered at a single node.

conditions of an emergency event. (Priority: Low. First reported 2012. Status: Not adopted.)

- The MMU recommends that shutdown cost be defined as the cost to curtail load for a given period that does not vary with the measured reduction or, for behind the meter generators, be the start cost defined in Manual 15 for generators. (Priority: Low. First reported 2012. Status: Not adopted.)
- The MMU recommends that the Net Benefits Test be eliminated and that demand response resources be paid LMP less any generation component of the applicable retail rate. (Priority: Low. First reported 2015. Status: Not adopted.)
- The MMU recommends that the tariff rules for demand response clarify that a resource and its CSP, if any, must notify PJM of material changes affecting the capability of the resource to perform as registered and must terminate or modify registrations that are no longer capable of responding to PJM dispatch directives at defined levels because load has been reduced or eliminated, as in the case of bankrupt and/or out of service facilities. (Priority: Medium. First reported 2015. Status: Not adopted.)
- The MMU recommends that there be only one demand response product in the capacity market, with an obligation to respond when called for any hour of the delivery year. (Priority: High. First reported 2011. Status: Partially adopted.[30])
- The MMU recommends that the lead times for demand resources be shortened to 30 minutes with a one hour minimum dispatch for all resources. (Priority: Medium. First reported 2013. Status: Partially adopted.)
- The MMU recommends setting the baseline for measuring capacity compliance under winter compliance at the customers' PLC, similar to GLD, to avoid double counting. (Priority: High. First reported 2010. Status: Partially adopted.)
- The MMU recommends the Relative Root Mean Squared Test be required for all demand resources with a CBL. (Priority: Low. First reported 2017. Status: Partially adopted.)
- The MMU recommends that the limits imposed on the pre-emergency and emergency demand response share of the synchronized reserve market be eliminated. (Priority: Medium. First reported 2018. Status: Not adopted.)
- The MMU recommends that 30 minute pre-emergency and emergency demand response be considered to be 30 minute reserves. (Priority: Medium. First reported 2018. Status: Not adopted.)
- The MMU recommends that energy efficiency resources not be included in the capacity market and that PJM should ensure that the impact of EE measures on the load forecast is incorporated immediately rather than with the existing lag. (Priority: Medium. First reported 2018. Status: Partially adopted.)
- The MMU recommends that, if energy efficiency resources remain in the capacity market, PJM codify eligibility requirements to claim the capacity rights to energy efficiency installations in the tariff and that PJM institute a registration system to track claims to capacity rights to energy efficiency installations and document installation periods of energy efficiency installations. (Priority: Medium. First reported 2022. Status: Not adopted.)
- The MMU recommends that demand reductions based entirely on behind the meter generation be capped at the lower of economic maximum or actual generation output. (Priority: High. First reported 2019. Status: Not adopted.)
- The MMU recommends that all demand resources register as Pre-Emergency Load Response and that the Emergency Load Response Program be eliminated. (Priority: High. First reported 2020. Status: Not adopted.)
- The MMU recommends that EDCs not be allowed to participate in markets as DER aggregators in addition to their EDC role. (Priority: High. First reported 2021. Status: Not adopted.)
- The MMU recommends that PJM include a 5.0 MW maximum size cap on DER aggregations. (Priority: Medium. First reported 2021. Status: Not adopted.)

30 PJM's Capacity Performance design requires resources to respond when called for any hour of the delivery year, but demand resources still have a limited mandatory compliance window.

- The MMU recommends that PJM use a nodal approach for DER participation in PJM markets. (Priority: Medium. First reported 2022. Status: Partially adopted.)

Section 7, Net Revenue

- The MMU recommends that the net revenue calculation used by PJM to calculate the net Cost of New Entry (CONE) and net ACR be based on a forward looking calculation of expected energy and ancillary services net revenues using forward prices for energy and fuel. (Priority: Medium. First reported 2019. Status: Not adopted.)

Section 8, Environmental and Renewables

- The MMU recommends that renewable energy credit markets based on state renewable portfolio standards be brought into PJM markets as they are an increasingly important component of the wholesale energy market. The MMU recommends that there be a single PJM operated forward market for RECs, for a single product based on a common set of state definitions of renewable technologies, with a single clearing price, trued up to real time delivery. (Priority: High. First reported 2010. Status: Not adopted.)
- The MMU recommends that PJM provide a full analysis of the impact of carbon pricing on PJM generating units and carbon pricing revenues to the PJM states in order to permit the states to consider a potential agreement on the development of a multistate framework for carbon pricing and the distribution of carbon revenues. (Priority: High. First reported 2018. Status: Not adopted.)
- The MMU recommends that jurisdictions with a renewable portfolio standard make the price and quantity data on supply and demand more transparent. (Priority: Low. First reported 2018. Status: Not adopted.)
- The MMU recommends that the Commission reconsider its disclaimer of jurisdiction over RECs markets because, given market changes since that decision, it is clear that RECs materially affect jurisdictional rates. (Priority: Low. First reported 2018. Status: Not adopted.)
- The MMU recommends that load and generation located at separate nodes be treated as separate resources in order to ensure that load and generation face consistent incentives throughout the markets. (Priority: High. First reported 2019. Status: Not adopted.)
- The MMU recommends that emergency stationary RICE be prohibited from participation as DR either when registered individually or as part of a portfolio if it cannot meet the capacity market requirements to be DR as a result of emissions standards that impose environmental run hour limitations. (Priority: Medium. First reported 2019. Status: Not adopted.)

Section 9, Interchange Transactions

- The MMU recommends that PJM implement rules to prevent sham scheduling. The MMU recommends that PJM apply after the fact market settlement adjustments to identified sham scheduling segments to ensure that market participants cannot benefit from sham scheduling. (Priority: High. First reported 2012. Status: Not adopted.)
- The MMU recommends that PJM implement a validation method for submitted transactions that would prohibit market participants from breaking transactions into smaller segments to defeat the interface pricing rule by concealing the true source or sink of the transaction. (Priority: Medium. First reported 2013. Status: Not adopted.)
- The MMU recommends that PJM implement a validation method for submitted transactions that would require market participants to submit transactions on paths that reflect the expected actual power flow in order to reduce unscheduled loop flows. (Priority: Medium. First reported 2013. Status: Not adopted.)
- The MMU recommends that transactions sourcing in the Western Interconnection be priced at either the MISO interface pricing point or the SOUTH interface pricing point based on the locational price impact of flows between the DC tie line point of connection with the Eastern Interconnection and PJM. (Priority: High. First reported 2020. Status: Not adopted.)

- The MMU recommends that PJM eliminate the IMO interface pricing point, and assign the transactions that originate or sink in the IESO balancing authority to the MISO interface pricing point. (Priority: Medium. First reported 2013. Status: Not adopted.)
- The MMU recommends that PJM monitor, and adjust as necessary, the weights applied to the components of the interfaces to ensure that the interface prices reflect ongoing changes in system conditions. The MMU also recommends that PJM review the mappings of external balancing authorities to individual interface pricing points to reflect changes to the impact of the external power source on PJM tie lines as a result of system topology changes. The MMU recommends that this review occur at least annually. (Priority: Low. First reported 2009. Status: Not adopted.)
- The MMU recommends that, in order to permit a complete analysis of loop flow, FERC and NERC ensure that the identified data are made available to market monitors as well as other industry entities determined appropriate by FERC. (Priority: Medium. First reported 2003. Status: Not adopted.)
- The MMU recommends that PJM explore an interchange optimization solution with its neighboring balancing authorities that would remove the need for market participants to schedule physical transactions across seams. Such a solution would include an optimized, but limited, joint dispatch approach that uses supply curves and treats seams between balancing authorities as constraints, similar to other constraints within an LMP market. (Priority: Medium. First reported 2014. Status: Not adopted.)
- The MMU recommends that PJM permit unlimited spot market imports as well as unlimited nonfirm point to point willing to pay congestion imports and exports at all PJM interfaces in order to improve the efficiency of the market. (Priority: Medium. First reported 2012. Status: Not adopted.)
- The MMU recommends that the emergency interchange cap be replaced with a market based solution. (Priority: Low. First reported 2015. Status: Not adopted.)
- The MMU recommends that the submission deadline for real-time dispatchable transactions be modified from 1800 on the day prior, to three hours prior to the requested start time, and that the minimum duration be modified from one hour to 15 minutes. These changes would give PJM a more flexible product that could be used to meet load in the most economic manner. (Priority: Medium. First reported 2014. Status: Partially adopted, 2015.)
- The MMU recommends modifications to the FFE calculation to ensure that FFE calculations reflect the current capability of the transmission system as it evolves. The MMU recommends that the Commission set a deadline for PJM and MISO to resolve the FFE freeze date and related issues. (Priority: Medium. First reported 2019. Status: Not adopted.)
- The MMU recommends clear, explicit and detailed rules that define the conditions under which PJM will and will not recall energy from PJM capacity resources and prohibit new energy exports from PJM capacity resources. The MMU recommends that those rules define the conditions under which PJM will purchase emergency energy while at the same time not recalling energy exports from PJM capacity resources. The MMU recommends clear rules governing when PJM may recall capacity backed exports. (Priority: Medium. First reported 2010. Status: Partially adopted.)

Section 10, Ancillary Services

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 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.[31])
- The MMU recommends that the two signal regulation market design be replaced with a one signal regulation market design. (Priority: Medium. New recommendation. Status: Not adopted.)
- 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.[32] FERC rejected.[33])
- 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.[34])
- 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.[35])
- The MMU recommends enhanced documentation of the implementation of the regulation market design. (Priority: Medium. First reported 2010. Status: Not adopted. FERC rejected.[36])
- 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

31 162 FERC ¶ 61,295 (2018), *reh'g denied*, 170 FERC ¶ 61,259 (2020).
32 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.
33 162 FERC ¶ 61,295 (2018), *reh'g denied*, 170 FERC ¶ 61,259 (2020).
34 *Id.*
35 *Id.*
36 *Id.*

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.)
- 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 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 black start planning and coordination be on a regional basis and not on a zonal basis and that the costs of black start service be shared equally across the region. (Priority: medium. New recommendation. 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.[37] 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 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.[38] (Priority: Medium. First reported 2020. Status: Not adopted.)

Section 11, Congestion and Marginal Losses

There are no recommendations in this section.

Section 12, Planning

Generation Retirements

- The MMU recommends that the question of whether Capacity Interconnection Rights (CIRs) should persist after the retirement of a unit be addressed. The rules need to ensure that incumbents cannot exploit control of CIRs to block or postpone entry of competitors.[39] (Priority: Medium. First reported 2013. Status: Partially adopted, 2012.)

Generation Queue

- Given the significance of data to market participants and regulators, the MMU recommends that all queue data and supplemental, network and baseline project data, including projected in service dates and estimated and final costs, be regularly updated with accurate and verifiable data. (Priority: High. New recommendation. Not adopted.)
- The MMU recommends that barriers to entry be addressed in a timely manner in order to help ensure that the capacity market will result in the entry of new capacity to meet the needs of PJM market participants. (Priority: Low. First reported 2012. Status: Not adopted.)
- The MMU recommends improvements in queue management including that PJM establish a review process to ensure that projects are removed from the queue if they are not viable, as well as a process to allow commercially viable projects to advance in the queue ahead of projects which have failed to make progress, subject to rules to prevent gaming.[40] (Priority: Medium. First reported 2013. Status: Partially adopted.)
- The MMU recommends continuing analysis of the study phase of PJM's transmission planning to reduce the need for postponements of study results, to decrease study completion times, and to improve the likelihood that a project at a given phase in the study process will successfully go into service.[41] (Priority: Medium. First reported 2014. Status: Partially adopted.)
- The MMU recommends outsourcing interconnection studies to an independent party to avoid potential conflicts of interest. Currently, these studies are performed by incumbent transmission owners under PJM's direction. This creates potential conflicts of interest, particularly when transmission owners are vertically integrated and the owner of transmission also owns generation. (Priority: Low. First reported 2013. Status: Not adopted.)

Market Efficiency Process

- The MMU recommends that the market efficiency process be eliminated because it is not consistent with a competitive market design. (Priority: Medium. First reported 2019. Status: Not adopted.)
- The MMU recommends that, if the market efficiency process is retained, PJM modify the rules governing cost/benefit analysis, the evaluation process for selecting among competing market efficiency projects and cost allocation for economic projects in order to ensure that all costs,

37 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.

38 *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>.

39 See Comments of the Independent Market Monitor for PJM, Docket No. ER12-1177-000 (March 12, 2012) <http://www.monitoringanalytics.com/Filings/2012/IMM_Comments_ER12-1177-000_20120312.PDF>.

40 PJM Filing, FERC Docket No. ER22-2110-000 (June 14, 2022); 181 FERC ¶ 61,162 (2022).

41 Ibid.

including increased congestion costs and the risk of project cost increases, in all zones are included in order to ensure that the correct metrics are used for defining benefits. (Priority: Medium. First reported 2018. Status: Not adopted.)

Comparative Cost Framework

- The MMU recommends that PJM modify the project proposal templates to include data necessary to perform a detailed project lifetime financial analysis. The required data includes, but is not limited to: capital expenditure; capital structure; return on equity; cost of debt; tax assumptions; ongoing capital expenditures; ongoing maintenance; and expected life. (Priority: Medium. First reported 2020. Status: Not adopted.)

Transmission Competition

- The MMU recommends, to increase the role of competition, that the exemption of supplemental projects from the Order No. 1000 competitive process be terminated and that the basis for all such exemptions be reviewed and modified to ensure that the supplemental project designation is not used to exempt transmission projects from a transparent, robust and clearly defined mechanism to permit competition to build such projects or to effectively replace the RTEP process. (Priority: Medium. First reported 2017. Status: Not adopted. Rejected by FERC.)[42]
- The MMU recommends, to increase the role of competition, that the exemption of end of life projects from the Order No. 1000 competitive process be terminated and that end of life transmission projects be included in the RTEP process and should be subject to a transparent, robust and clearly defined mechanism to permit competition to build such projects. (Priority: Medium. First reported 2019. Status: Not adopted. Rejected by FERC.)[43]
- The MMU recommends that PJM enhance the transparency and queue management process for nonincumbent transmission investment. Issues related to data access and complete explanations of cost impacts should be addressed. The goal should be to remove barriers to competition from nonincumbent transmission providers. (Priority: Medium. First reported 2015. Status: Not adopted.)
- The MMU recommends that PJM continue to incorporate the principle that the goal of transmission planning should be the incorporation of transmission investment decisions into market driven processes as much as possible. (Priority: Low. First reported 2001. Status: Not adopted.)
- The MMU recommends the creation of a mechanism to permit a direct comparison, or competition, between transmission and generation alternatives, including which alternative is less costly and who bears the risks associated with each alternative. (Priority: Low. First reported 2013. Status: Not adopted.)
- The MMU recommends that PJM establish fair terms of access to rights of way and property, such as at substations, in order to remove any barriers to entry and permit competition between incumbent transmission providers and nonincumbent transmission providers in the RTEP. (Priority: Medium. First reported 2014. Status: Not adopted.)
- The MMU recommends that rules be implemented to permit competition to provide financing for transmission projects. This competition could reduce the cost of capital for transmission projects and significantly reduce total costs to customers. (Priority: Low. First reported 2013. Status: Not adopted.)
- The MMU recommends that storage resources not be includable as transmission assets for any reason. (Priority: High. First reported 2020. Status: Not adopted.)

Cost Allocation

- The MMU recommends a comprehensive review of the ways in which the solution based dfax is implemented. The goal for such a process would be to ensure that the most rational and efficient approach to implementing

42 The FERC accepted tariff provisions that exclude supplemental projects from competition in the RTEP. 162 FERC ¶ 61,129 (2018), *reh'g denied*, 164 FERC ¶ 61,217 (2018).

43 In recent decisions addressing competing proposals on end of life projects, the Commission accepted a transmission owner proposal excluding end of life projects from competition in the RTEP process, 172 FERC ¶ 61,136 (2020), *reh'g denied*, 173 FERC ¶ 61,225 (2020), and rejected a proposal from PJM stakeholders that would have included end of life projects in competition in the RTEP process, 173 FERC ¶ 61,242 (2020).

the solution based dfax method is used in PJM. Such an approach should allocate costs consistent with benefits and appropriately calibrate the incentives for investment in new transmission capability. No replacement approach should be approved until all potential alternatives, including the status quo, are thoroughly reviewed. (Priority: Medium. First reported 2020. Status: Not adopted.)

- The MMU recommends changing the minimum distribution factor in the allocation from 0.01 to 0.00 and adding a threshold minimum usage impact on the line.[44] (Priority: Medium. First reported 2015. Status: Not adopted.)

Transmission Line Ratings

- The MMU recommends that all PJM transmission owners use the same methods to define line ratings and that all PJM transmission owners implement dynamic line ratings (DLR), subject to NERC standards and guidelines, subject to review by NERC, PJM and the MMU, and approval by FERC. (Priority: Medium. First reported 2019. Status: Not adopted.)

Transmission Facility Outages

- The MMU recommends that PJM reevaluate all transmission outage tickets as on time or late as if they were new requests when an outage is rescheduled, create options for late requests based on the reasons, and apply the modified rules for late submissions to any such outages. (Priority: Low. First reported 2014. Status: Not adopted.)
- The MMU recommends that PJM draft a clear definition of the congestion analysis required for transmission outage requests and associated triggers, including both the extent of overloaded facilities and the level of economic congestion, to include in Manual 3 after appropriate review. (Priority: Medium. First reported 2015. Status: Not adopted.)
- The MMU recommends that PJM create options for late requests based on the reasons, and modify the rules to reduce or eliminate the approval of late outage requests submitted or rescheduled after the FTR auction bidding opening date, based on those options. (Priority: Low. First reported 2015. Status: Not adopted.)
- The MMU recommends that PJM not permit transmission owners to divide long duration outages into smaller segments to avoid complying with the requirements for long duration outages. (Priority: Low. First reported 2015. Status: Not adopted.)

Section 13, FTRs and ARRs

Market Design

- The MMU recommends that the current ARR/FTR design be replaced with defined congestion revenue rights (CRRs). A CRR is the right to actual congestion that is paid by physical load at a specific bus, zone or aggregate. (Priority: High. First reported 2015. Status: Not adopted.)

ARR

- The MMU recommends that the ARR/FTR design be modified to ensure that the rights to all congestion revenues are assigned to load. (Priority: High. First reported 2015. Status: Not adopted.)
- The MMU recommends that all historical generation to load paths be eliminated as a basis for assigning ARRs. The MMU recommends that the current design be replaced with a design in which the rights to actual congestion paid are assigned directly to the load that paid that congestion by node. (Priority: High. First reported 2015. Status: Partially adopted.)
- The MMU recommends that, under the current FTR design, the rights to all congestion revenue be allocated as ARRs prior to sale as FTRs. Reductions for outages and increased system capability should be reserved for ARRs rather than sold in the Long Term FTR Auction. (Priority: High. First reported 2017. Status: Not adopted.)
- The MMU recommends that IARRs be eliminated from PJM's tariff, but that if IARRs are not eliminated, IARRs should be subject to the same proration rules that apply to all other ARR rights. (Priority: Low. First reported 2018. Status: Not adopted.)

44 See *2015 State of the Market Report for PJM*, Volume II, Section 12: Generation and Transmission Planning, at 463, Cost Allocation Issues.

FTR

- The MMU recommends that FTR funding be based on total congestion, including day-ahead and balancing congestion. (Priority: High. First reported 2017. Status: Not adopted.)
- The MMU recommends that bilateral transactions be eliminated and that all FTR transactions occur in the PJM market. (Priority: High. First reported Q1 2022. Status: Not adopted.)[45]
- The MMU recommends a requirement that the details of all bilateral FTR transactions be reported to PJM. (Priority: High. First reported 2020. Status: Not adopted.)
- The MMU recommends that PJM continue to evaluate the bilateral indemnification rules and any asymmetries they may create. (Priority: Low. First reported 2018. Status: Not adopted.)
- The MMU recommends that PJM reduce FTR sales on paths with persistent overallocation of FTRs, including a clear definition of persistent overallocation and how the reduction will be applied. (Priority: High. First reported 2013. Status: Partially adopted, 2014/2015 planning period.)
- The MMU recommends that PJM eliminate generation to generation paths and all other paths that do not represent the delivery of power to load. (Priority: High. First reported 2018. Status: Not adopted.)
- The MMU recommends that the Long Term FTR product be eliminated. If the Long Term FTR product is not eliminated, the Long Term FTR Market should be modified so that the supply of prevailing flow FTRs in the Long Term FTR Market is based solely on counter flow offers in the Long Term FTR Market. (Priority: High. First reported 2017. Status: Not adopted.)
- The MMU recommends that PJM improve transmission outage modeling in the FTR auction models, including the use of probabilistic outage modeling. (Priority: Low. First reported 2013. Status: Not adopted.)

Surplus

- The MMU recommends that all FTR auction revenue be distributed to ARR holders monthly, regardless of FTR funding levels. (Priority: High. First reported 2015. Status: Not adopted.)
- The MMU recommends that, under the current FTR design, all congestion revenue in excess of FTR target allocations be distributed to ARR holders on a monthly basis. (Priority: High. First reported 2018. Status: Not adopted.)
- The MMU recommends that FTR auction revenues not be used by PJM to buy counter flow FTRs for the purpose of improving FTR payout ratios.[46] (Priority: High. First reported 2015. Status: Not adopted.)

FTR Subsidies

- The MMU recommends that PJM eliminate portfolio netting to eliminate cross subsidies among FTR market participants. (Priority: High. First reported 2012. Status: Not adopted. Rejected by FERC.)
- The MMU recommends that PJM eliminate subsidies to counter flow FTRs by applying the payout ratio to counter flow FTRs in the same way the payout ratio is applied to prevailing flow FTRs. (Priority: High. First reported 2012. Status: Not adopted.)
- The MMU recommends that PJM eliminate geographic cross subsidies. (Priority: High. First reported 2013. Status: Not adopted.)
- The MMU recommends that PJM examine the mechanism by which self scheduled FTRs are allocated when load switching among LSEs occurs throughout the planning period. (Priority: Low. First reported 2011. Status: Not adopted.)

FTR Liquidation

- The MMU recommends that the FTR portfolio of a defaulted member be canceled rather than liquidated or allowed to settle as a default cost on the membership. (Priority: High. First reported 2018. Status: Not adopted.)

45 If adopted, this recommendation would replace the next two recommendations.

46 See "PJM Manual 6: Financial Transmission Rights," Rev. 29 (Sep. 1, 2022).

Credit

- The MMU recommends the use of a 99 percent confidence interval when calculating initial margin requirements for FTR market participants, in order to assign the cost of managing risk to the FTR holders who benefit or lose from their FTR positions. (Priority: High. First reported 2021. Status: Not adopted.)

Energy Market

The PJM energy market comprises all types of energy transactions, including the sale or purchase of energy in PJM's Day-Ahead and Real-Time Energy Markets, bilateral and forward markets and self supply. Energy transactions analyzed in this report include those in the PJM Day-Ahead and Real-Time Energy Markets. These markets provide key benchmarks against which market participants may measure results of transactions in other markets.

The Market Monitoring Unit (MMU) analyzed measures of market structure, participant conduct and market performance, including market size, concentration, pivotal suppliers, offer behavior, markup, and price. The MMU concludes that the PJM energy market results were competitive in the first three months of 2023.

Table 3-1 The energy market results were competitive

Market Element	Evaluation	Market Design
Market Structure: Aggregate Market	Partially Competitive	
Market Structure: Local Market	Not Competitive	
Participant Behavior	Competitive	
Market Performance	**Competitive**	**Effective**

- The aggregate market structure was evaluated as partially competitive because the aggregate market power test based on pivotal suppliers indicates that the aggregate day-ahead market structure was not competitive on 17.8 percent of days. The hourly HHI (Herfindahl-Hirschman Index) results indicate that the PJM aggregate energy market in the first three months of 2023 was, on average, unconcentrated by FERC HHI standards. The average HHI was 677 with a minimum of 575 and a maximum of 921. The baseload segment of the supply curve was unconcentrated. The intermediate segment of the supply curve was moderately concentrated. The peaking segment of the supply curve was highly concentrated. The fact that the average HHI is in the unconcentrated range does not mean that the aggregate market was competitive in all hours. As demonstrated for the day-ahead market, it is possible to have pivotal suppliers in the aggregate market even when the HHI level is not in the highly concentrated range. It is possible to have an exercise of market power even when the HHI level is not in the highly concentrated range. The number of pivotal suppliers in the energy market is a more precise measure of structural market power than the HHI. The HHI is not a definitive measure of structural market power.
- The local market structure was evaluated as not competitive due to the highly concentrated ownership of supply in local markets created by transmission constraints and local reliability issues. The results of the three pivotal supplier (TPS) test, used to test local market structure, indicate the existence of market power in local markets created by transmission constraints. The local market performance is competitive as a result of the application of the TPS test. Transmission constraints create the potential for the exercise of local market power. The goal of PJM's application of the three pivotal supplier test is to identify local market power and offer cap to competitive offers, correcting for structural issues created by local transmission constraints. There are, however, identified issues with the definition of cost-based offers and the application of market power mitigation to resources whose owners fail the TPS test that need to be addressed because unit owners can exercise market power even when they fail the TPS test.
- Participant behavior was evaluated as competitive because the analysis of markup shows that marginal units generally make offers at, or close to, their marginal costs in both the day-ahead and real-time energy markets, although the behavior of some participants both routinely and during periods of high demand represents economic withholding. The ownership of marginal units is concentrated. The markups of pivotal suppliers in the aggregate market and of many pivotal suppliers in local markets remain unmitigated due to the lack of aggregate market power mitigation and the flawed implementation of offer caps for resources that fail the TPS test. The markups of those participants affected LMP.
- Market performance was evaluated as competitive because market results in the energy market reflect the outcome of a competitive market, as PJM prices are set, on average, by marginal units operating at, or close to, their

marginal costs in both day-ahead and real-time energy markets, although high markups for some marginal units did affect prices.

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

- PJM markets are designed to promote competitive outcomes derived from the interaction of supply and demand in each of the PJM markets. Market design itself is the primary means of achieving and promoting competitive outcomes in PJM markets. One of the MMU's core functions is to identify actual or potential market design flaws.[1] The approach to market power mitigation in PJM has focused on market designs that promote competition (a structural basis for competitive outcomes) and on mitigating market power in instances where the market structure is not competitive and thus where market design alone cannot mitigate market power. FERC relies on effective market power mitigation when it approves market sellers to participate in the PJM market at market based rates.[2] In the PJM energy market, market power mitigation occurs primarily in the case of local market power. When a transmission constraint creates the potential for local market power, PJM applies a structural test to determine if the local market is competitive, applies a behavioral test to determine if generator offers exceed competitive levels and applies a market performance test to determine if such generator offers would affect the market price.[3] There are, however, identified issues with the application of market power mitigation to resources whose owners fail the TPS test that can result in the exercise of local market power even when market power mitigation rules are applied. These issues need to be addressed. FERC recognized these issues in its June 17, 2021 order.[4] Some units with market power have positive markups and some have inflexible parameters, which means that the cost-based offer was not used and that the process for offer capping units that fail the TPS test does not consistently result in competitive market outcomes in the presence of market power. There are issues related to the definition of gas costs includable in energy offers that need to be addressed. There are issues related to the level of maintenance expense includable in energy offers that need to be addressed. There are currently no market power mitigation rules in place that limit the ability to exercise market power when aggregate market conditions are tight and there are pivotal suppliers in the aggregate market. Aggregate market power needs to be addressed. Market design must reflect appropriate incentives for competitive behavior, the application of local market power mitigation needs to be fixed, the definition of a competitive offer needs to be fixed, and aggregate market power mitigation rules need to be developed. The importance of these issues is amplified by the rules permitting cost-based offers in excess of $1,000 per MWh.

1 OATT Attachment M (PJM Market Monitoring Plan).

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

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

4 175 FERC ¶ 61,231 (2021).

Overview

Supply and Demand

Market Structure

- **Supply.** In the first three months of 2023, 146 MW of new resources were added in the energy market, and 0 MW of resources were retired.
- The real-time hourly on peak average offered supply was 148,236 MW in the winter of 2021/2022, and 141,798 MW in the winter of 2022/2023. The day-ahead hourly on peak average offered supply was 168,965 MW in the winter of 2021/2022, and 163,028 MW in the winter of 2022/2023.
- The real-time hourly average cleared generation in the first three months of 2023 decreased by 5.7 percent from the first three months of 2022, from 98,506 MWh to 92,936 MWh.
- The day-ahead hourly average supply in the first three months of 2023, including INCs and UTCs, increased by 7.3 percent from the first three months of 2022, from 113,169 MWh to 121,433 MWh.
- **Demand.** The real-time hourly peak load plus exports in the first three months of 2023 was 123,504 MWh (117,705 MWh of load plus 5,798 MWh of gross exports) in the HE 2000 (EPT) on February 03, 2023, which was 5.6 percent, 7,276 MWh, lower than the PJM peak load plus exports in the first three months of 2022, which was 130,779 MWh in the HE 0800 (EPT) on January 27, 2022.
- The real-time hourly average load in the first three months of 2023 decreased by 5.1 percent from the first three months of 2022, from 92,007 MWh to 87,311 MWh.
- The day-ahead hourly average demand in the first three months of 2023, including DECs and UTCs, increased by 8.2 percent from the first three months of 2022, from 106,845 MWh to 115,558 MWh.

Market Behavior

- **Virtual Offers and Bids.** Any market participant in the PJM Day-Ahead Energy Market can use increment offers, decrement bids, up to congestion transactions, import transactions and export transactions as financial instruments that do not require physical generation or load. The hourly average submitted increment offer MW increased by 5.6 percent and cleared increment MW increased by 25.2 percent in the first three months of 2023 compared to the first three months of 2022. The hourly average submitted decrement bid MW decreased by 23.3 percent and cleared decrement MW decreased by 25.1 percent in the first three months of 2023 compared to the first three months of 2022. The hourly average submitted up to congestion bid MW increased by 186.1 percent and cleared up to congestion bid MW increased by 135.2 percent in the first three months of 2023 compared to the first three months of 2022.

Market Performance[5]

- **Generation Fuel Mix.** In the first three months of 2023, generation from coal units decreased 40.1 percent, generation from natural gas units increased 12.5 percent, and generation from oil decreased 11.9 percent compared to the first three months of 2022. Wind and solar output rose by 3.6 percent compared to the first three months of 2022, supplying 5.8 percent of PJM energy in the first three months of 2023.
- **Fuel Diversity.** The fuel diversity of energy generation in the first three month of 2023, measured by the fuel diversity index for energy (FDI_e), decreased 4.1 percent compared to the first three months of 2022.
- **Marginal Resources.** In the PJM Real-Time Energy Market in the first three months of 2023, coal units were 11.6 percent and natural gas units were 79.0 percent of marginal resources. In the first three months of 2022, coal units were 15.3 percent and natural gas units were 63.6 percent of marginal resources.

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

In the PJM Day-Ahead Energy Market in the first three months of 2023, UTCs were 57.3 percent, INCs were 13.3 percent, DECs were 16.9 percent, and generation resources were 12.1 percent of marginal resources. In the first three months of 2022, UTCs were 37.4 percent, INCs were 20.1 percent, DECs were 24.9 percent, and generation resources were 17.5 percent of marginal resources.

- **Prices.** The real-time load-weighted average LMP in the first three months of 2023 decreased 44.1 percent from the first three months of 2022, from $54.13 per MWh to $30.28 per MWh.

  The day-ahead load-weighted average LMP in the first three months of 2023 decreased 40.7 percent from the first three months of 2022, from $54.23 per MWh to $32.16 per MWh.

- **Fast Start Pricing.** The real-time load-weighted average PLMP was $30.28 per MWh for the first three months of 2023, which is 2.9 percent, $0.85 per MWh, higher than the real-time load-weighted average DLMP of $29.43 per MWh.

- **Components of LMP.** In the PJM Real-Time Energy Market in the first three months of 2023, 18.2 percent of the load-weighted LMP was the result of coal costs, 53.7 percent was the result of gas costs, 5.3 percent was the result of the cost of emission allowances, 2.5 percent was the result of transmission constraint violation penalty factors, and, 1.6 percent was the result of the commitment costs of fast start units.

  Of the $23.85 per MWh decrease in the real-time load weighted average LMP, $13.89 per MWh (58.2 percent) was in the fuel and consumables cost components of LMP, $0.26 per MWh (1.1 percent) was in the emissions cost components of LMP, $3.88 per MWh (14.0 percent) was in the sum of the markup, maintenance, and ten percent adder components of LMP, $3.65 per MWh (15.3 percent) was in the transmission constraint penalty factor component of LMP, and $0.50 per MWh (2.1 percent) was in the scarcity component of LMP.

  In the PJM Day-Ahead Energy Market in the first three months of 2023, 23.4 percent of the load-weighted LMP was the result of gas costs, 20.5 percent was the result of coal costs, 16.9 percent was the result of DEC bids, 21.9 percent was the result of INC offers, 7.9 percent was the result of positive markup, and 3.0 percent was the result of UTCs.

  Of the $21.83 per MWh decrease in the day-ahead load weighted average LMP, $11.50 per MWh (52.7 percent) was in the virtual and dispatchable transactions cost components of LMP, $6.54 per MWh (29.9 percent) was in the fuel and consumables cost components of LMP, $0.46 per MWh (2.1 percent) was in the emissions cost components of LMP, $3.37 per MWh (15.4 percent) was in the sum of the markup, maintenance, and ten percent adder components of LMP.

- **Price Convergence.** Hourly and daily price differences between the day-ahead and real-time energy markets fluctuate continuously and substantially from positive to negative. The difference between day-ahead and real-time average prices was -$1.68 per MWh in the first three months of 2023, and -$0.30 per MWh in the first three months of 2022. The difference between day-ahead and real-time average prices, by itself, is not a measure of the competitiveness or effectiveness of the day-ahead energy market.

Scarcity

- There were three intervals with five minute shortage pricing on one day in the first three months of 2023. These shortages did not correspond with any emergency warning or action.
- There were 351 five minute intervals, or 1.4 percent of all five minute intervals, in the first three months of 2023 for which at least one RT SCED solution showed a shortage of reserves, and 101 five minute intervals, or 0.4 percent of all five minute intervals, in the first three months of 2023 for which more than one RT SCED solution showed a shortage of reserves. PJM triggered shortage pricing for three five minute intervals, or 0.01 percent of all five minute intervals.

Competitive Assessment

Market Structure

- **Aggregate Pivotal Suppliers.** The PJM energy market, at times, requires generation from pivotal suppliers to meet load, resulting in aggregate market power even when the HHI level indicates that the aggregate market is unconcentrated. Three suppliers were jointly pivotal in the day-ahead market on 16 days, 17.8 percent of days, in the first three months of 2023 and 66 days, 73.3 percent of days, in the first three months of 2022.
- **Local Market Power.** In the first three months of 2023, in the real-time market, nine zones experienced congestion resulting from one or more constraints binding for 25 or more hours. For seven out of the top 10 congested facilities (by real-time binding hours) in the first three months of 2023, the average number of suppliers providing constraint relief was three or fewer. There was a high level of concentration within the local markets for providing relief to the most congested facilities in the PJM Real-Time Energy Market. The local market structure was not competitive.

Market Behavior

- **Offer Capping for Local Market Power.** PJM offer caps units when the local market structure is noncompetitive. Offer capping is an effective means of addressing local market power when the rules are designed and implemented properly. Offer capping levels have historically been low in PJM. In the day-ahead energy market, for units committed to provide energy for local constraint relief, offer-capped unit hours decreased from 1.4 percent in the first three months of 2022 to 1.1 percent in the first three months of 2023. In the real-time energy market, for units committed to provide energy for local constraint relief, offer-capped unit hours decreased from 1.1 percent in the first three months of 2022 to 0.7 percent in the first three months of 2023. While overall offer capping levels have been low, there are a significant number of units with persistent structural local market power that would have had a significant impact on prices in the absence of local market power mitigation.

  The analysis of the application of the TPS test to local markets demonstrates that it is working to identify pivotal owners when the market structure is noncompetitive and to ensure that owners are not subject to offer capping when the market structure is competitive. There are, however, identified issues with the application of market power mitigation to resources whose owners fail the TPS test that can result in the exercise of local market power. These issues need to be addressed.
- **Offer Capping for Reliability.** PJM also offer caps units that are committed for reliability reasons, including for reactive support. In the day-ahead energy market, for units committed for reliability reasons, offer-capped unit hours increased from 0.00 percent in the first three months of 2022 to 0.06 percent in the first three months of 2023. In the real-time energy market, for units committed for reliability reasons, offer-capped unit hours increased from 0.00 percent in the first three months of 2022 to 0.03 percent in the first three months of 2023. The low offer cap percentages do not mean that units manually committed for reliability reasons do not have market power. All units manually committed for reliability have market power and all are treated as if they had market power. These units are not capped to their cost-based offers because they tend to offer with a negative markup in their price-based offers, particularly at the economic minimum level, which means that PJM's offer capping process results in the use of the price-based offer for commitment even if it has less flexible operating parameters.
- **Parameter Mitigation.** In the first three months of 2023, 34.6 percent of unit hours for units that failed the TPS test in the day-ahead market were committed on price-based schedules that were less flexible than their cost-based schedules. On days when cold weather alerts and hot weather alerts were declared, 27.0 percent of unit hours in the day-ahead energy market were committed on price-based schedules that were less flexible than their price PLS schedules.
- **Frequently Mitigated Units (FMU) and Associated Units (AU).** In the first three months of 2023, no units qualified for an FMU adder. In 2022, no units qualified for an FMU adder. In 2021, one unit qualified for an FMU adder.

- **Markup Index.** The markup index is a summary measure of participant offer behavior for individual marginal units. While the average markup index in the real-time market was -0.02 in the first three months of 2023, some marginal units did have substantial markups. The highest markup for any marginal unit in the real-time market in the first three months of 2023 was more than $200 per MWh when using unadjusted cost-based offers.

  While the average markup index in the day-ahead market was 0.14 in the first three months of 2023, some marginal units did have substantial markups. The highest markup for any marginal unit in the day-ahead market in the first three months of 2023 was more than $100 per MWh when using unadjusted cost-based offers.

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

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

Market Performance

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

  In the PJM Real-Time Energy Market in the first three months of 2023, the unadjusted markup component of LMP was $0.07 per MWh or 0.2 percent of the PJM load-weighted average LMP. March had the highest unadjusted peak markup component, $0.66 per MWh, or 2.2 percent of the real-time peak hour load-weighted average LMP for March.

  In the PJM Day-Ahead Energy Market, INCs, DECs and UTCs have zero markups. In the first three months of 2023, the unadjusted markup component of LMP was $0.44 per MWh or 1.4 percent of the PJM day-ahead load-weighted average LMP. January had the highest unadjusted peak markup component, $1.09 per MWh, or 3.6 percent of the day-ahead peak hour load-weighted average LMP for January.[6]

  Participant behavior was evaluated as competitive because the analysis of markup shows that marginal units generally make offers at, or close to, their marginal costs in both the day-ahead and real-time energy markets, although the behavior of some participants represents economic withholding.

- **Markup and Local Market Power.** Comparison of the markup behavior of marginal units with TPS test results shows that for 3.6 percent of all real-time marginal unit intervals in the first three months of 2023, the marginal unit had both local market power as determined by the TPS test and a positive markup. The fact that units with market power had a positive markup means that the cost-based offer was not used, that a higher price-based offer was used, and that the process for offer capping units that fail the TPS test does not consistently result in competitive market outcomes in the presence of market power.

- **Markup and Aggregate Market Power.** In the first three months of 2023, pivotal suppliers in the aggregate market, committed in the day-ahead market and identified as one of three day-ahead aggregate pivotal suppliers, set real-time market prices with markups over $50 per MWh on nine days.

Recommendations

Market Power

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

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

exceed the short run marginal cost of the unit. (Priority: Medium. First reported 2009. Status: Not adopted.)

Fuel Cost Policies

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

Cost-Based Offers

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

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

- The MMU recommends revising the pumped hydro fuel cost calculation to include day-ahead and real-time power purchases. (Priority: Low. First reported 2016. Status: Not adopted.)

Market Power: TPS Test and Offer Capping

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

Offer Behavior

- The MMU recommends that resources not be allowed to violate the ICAP must offer requirement. The MMU recommends that PJM enforce the ICAP must offer requirement by assigning a forced outage to any unit that is derated in the energy market below its committed ICAP without an outage that reflects the derate. (Priority: Medium. First reported 2020. Status: Not adopted.)
- The MMU recommends that storage and intermittent resources be subject to an enforceable ICAP must offer rule that reflects the limitations of these resources. (Priority: Medium. First reported 2020. Status: Not adopted.)
- The MMU recommends that capacity resources not be allowed to offer any portion of their capacity market obligation as maximum emergency energy. (Priority: Medium. First reported 2012. Status: Not adopted.)

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

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

- The MMU recommends that PJM integrate all the outage reporting tools in order to enforce the ICAP must offer requirement, ensure that outages are reported correctly and eliminate reporting inconsistencies. Generators currently submit availability in three different tools that are not integrated, Markets Gateway, eDART and eGADS. (Priority: Medium. First reported 2022. Status: Not adopted.)
- The MMU recommends that gas generators be required to check with pipelines throughout the operating day to confirm that nominations are accepted beyond the NAESB deadlines, and that gas generators be required to place their units on forced outage until the time that pipelines allow nominations to consume gas at a unit. (Priority: Medium. First reported Q1 2022. Status: Not adopted.)

Capacity Resources

- The MMU recommends that capacity resources be held to the OEM operating parameters of the capacity market CONE reference resource for performance assessment and energy uplift payments and that this standard be applied to all technologies on a uniform basis. (Priority: Medium. First reported 2015. Status: Not adopted.)
- The MMU recommends that the parameters which determine nonperformance charges and the amounts of uplift payments should reflect the flexibility goals of the capacity market design. The operational parameters used by generation owners to indicate to PJM operators what a unit is capable of during the operating day should not determine capacity resource performance assessment or uplift payments. (Priority: Medium. First reported 2015. Status: Partially adopted.)[10]
- The MMU recommends that PJM clearly define the business rules that apply to the unit specific parameter adjustment process, including PJM's implementation of the tariff rules in the PJM manuals to ensure market sellers know the requirements for their resources. (Priority: Low. First reported 2018. Status: Not adopted.)
- The MMU recommends that PJM update the tariff to clarify that all generation resources are subject to unit specific parameter limits on their cost-based offers using the same standard and process as capacity resources. (Priority: Medium. First reported 2018. Status: Not adopted.)
- The MMU recommends that resources not be paid the daily capacity payment when unable to operate to their unit specific parameter limits. (Priority: Medium. First reported 2018. Status: Not adopted.)
- The MMU recommends that PJM not approve temporary exceptions that are based on pipeline tariff terms that are not enforced at the time, or are based on inferior transportation service procured by the generator. (Priority: Medium. First reported 2019. Status: Not adopted.)
- The MMU recommends that PJM require generators that violate their approved turn down ratio (by either using the fixed gen option or increasing their economic minimum) to use the temporary parameter exception process that requires market sellers to demonstrate that the request is based on a physical and actual constraint. (Priority: Medium. First reported 2021. Status: Not adopted.)
- The MMU recommends: that gas generators be required to confirm, regularly during the operating day, that they can obtain gas if requested to operate at their economic maximum level; that gas generators provide that information to PJM during the operating day; and that gas generators be required to be on forced outage if they cannot obtain gas during the operating day to meet their must offer requirement as a result of pipeline restrictions, and they do not have backup fuel. As part of this, the MMU recommends that PJM collect data on each individual generator's fuel supply arrangements at least annually or when such arrangements change, and analyze the associated locational and regional risks to reliability. (Priority: Medium. First reported Q1 2022. Status: Not adopted.)
- The MMU recommends, if the capacity market seller offer cap were to be calculated using the historical average balancing ratio, that PJM not include the balancing ratios calculated for localized Performance Assessment Intervals (PAIs), and only include those events that trigger

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

emergencies at a defined zonal or higher level. (Priority: Medium. First reported 2018. Status: Not adopted.)

Accurate System Modeling

- The MMU recommends that PJM explicitly state its policy on the use of transmission penalty factors including: the level of the penalty factors; the triggers for the use of the penalty factors; the appropriate line ratings to trigger the use of penalty factors; the allowed duration of the violation and when the transmission penalty factors will be used to set the shadow price. The MMU recommends that PJM end the practice of discretionary reductions in transmission line ratings modeled in the market clearing and included in LMP. (Priority: Medium. First reported 2015. Status: Partially adopted 2020.)[11]
- The MMU recommends that PJM routinely review all transmission facility ratings and any changes to those ratings to ensure that the normal, emergency and load dump ratings used in modeling the transmission system are accurate and reflect standard ratings practice. (Priority: Low. First reported 2013. Status: Not adopted.)
- The MMU recommends that PJM not use closed loop interface or surrogate constraints to artificially override nodal prices based on fundamental LMP logic in order to: accommodate rather than resolve the inadequacies of the demand side resource capacity product; address the inability of the power flow model to incorporate the need for reactive power; accommodate rather than resolve the flaws in PJM's approach to scarcity pricing; or for any other reason. (Priority: Medium. First reported 2013. Status: Not adopted.)
- The MMU recommends that PJM update the outage impact studies, the reliability analyses used in RPM for capacity deliverability, and the reliability analyses used in RTEP for transmission upgrades to be consistent with the more conservative emergency operations (post contingency load dump limit exceedance analysis) in the energy market that were implemented in June 2013.[12] (Priority: Low. First reported 2013. Status: Not adopted.)
- The MMU recommends that PJM include in the tariff or appropriate manual an explanation of the initial creation of hubs, the process for modifying hub definitions and a description of how hub definitions have changed.[13] [14] (Priority: Low. First reported 2013. Status: Not adopted.)
- The MMU recommends that all buses with a net withdrawal be treated as load for purposes of calculating load and load-weighted LMP, even if the MW are settled to the generator. The MMU recommends that during hours when a load bus shows a net injection, the energy injection be treated as generation, not negative load, for purposes of calculating generation and load-weighted LMP, even if the injection MW are settled to the load serving entity. (Priority: Low. First reported 2013. Status: Not adopted.)
- The MMU recommends that PJM identify and collect data on available behind the meter generation resources, including nodal location information and relevant operating parameters. (Priority: Low. First reported 2013. Status: Partially adopted.)
- The MMU recommends that PJM document how LMPs are calculated when demand response is marginal. (Priority: Low. First reported 2014. Status: Not adopted.)
- The MMU recommends that PJM not allow nuclear generators which do not respond to prices or which only respond to manual instructions from the operator to set the LMPs in the real-time market. (Priority: Low. First reported 2016. Status: Not adopted.)
- The MMU recommends that PJM increase the coordination of outage and operational restrictions data submitted by market participants via eDART/eGADs and offer data submitted via Markets Gateway. (Priority: Low. First reported 2017. Status: Not adopted.)

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

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

13 According to minutes from the first meeting of the Energy Market Committee (EMC) on January 28, 1998, the EMC unanimously agreed to be responsible for approving additions, deletions and changes to the hub definitions to be published and modeled by PJM. Since the EMC has become the Market Implementation Committee (MIC), the MIC now appears to be responsible for such changes.

14 There is currently no PJM documentation in the tariff or manuals explaining how hubs are created and how their definitions are changed. The general definition of a hub can be found in the PJM.com Glossary <http://www.pjm.com/Glossary.aspx>.

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

Transparency

- The MMU recommends that PJM clearly document the calculation of shortage prices and implementation of reserve price caps in the PJM manuals, including defining all the components of reserve prices, and all the constraints whose shadow prices are included in reserve prices. (Priority: High. First reported 2021. Status: Not adopted.)
- The MMU recommends that PJM allow generators to report fuel type on an hourly basis in their offer schedules and to designate schedule availability on an hourly basis. (Priority: Medium. First reported 2015. Status: Partially adopted.)[15]

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

- The MMU recommends that PJM define clear criteria for operator approval of RT SCED cases, including shortage cases, that are used to send dispatch signals to resources, and for pricing, to minimize discretion. (Priority: High. First reported 2018. Status: Partially adopted.)[16]

Virtual Bids and Offers

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

Conclusion

The MMU analyzed key elements of PJM energy market structure, participant conduct and market performance in the first three months of 2023, including aggregate supply and demand, concentration ratios, aggregate pivotal supplier results, local three pivotal supplier test results, offer capping, markup, marginal units, participation in demand response programs, virtual bids and offers, loads and prices.

Prices are a key outcome of markets. Prices vary across hours, days and years for multiple reasons. Price is an indicator of the level of competition in a market. In a competitive market, prices are directly related to input prices, the marginal cost to serve load. In the first three months of 2023, LMP decreased by $23.85 per MWh compared to the first three months of 2022. The largest contributor to decreased prices was the cost of fuel, primarily natural gas and coal. The fuel cost components of LMP (the sum of gas, coal, oil, landfill gas, and consumables) decreased $13.89 per MWh, 58.2 percent of the decrease in LMP. The emissions cost components of LMP decreased by $0.26 per MWh, 1.1 percent of the decrease in LMP. The transmission constraint penalty factor component decreased by $1.64 per MWh, 6.9 percent of the decrease in LMP.

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

The pattern of prices within days and across months and years illustrates how prices are directly related to supply and demand conditions and illustrates the potential significance of the impact of the price elasticity of demand on prices. Energy market results in the first three months of 2023 generally reflected supply-demand fundamentals, although the behavior of some participants both routinely and during high demand periods represents economic withholding. Economic withholding occurs when generator offers are greater than competitive levels. In the first three months of 2023, the markup, ten percent adder, and maintenance cost components, together decreased by $3.35 per MWh or 14.0 percent of the decrease in LMP.

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

With or without a capacity market, energy market design must permit scarcity pricing when such pricing is consistent with market conditions and constrained by reasonable rules to ensure that market power is not exercised and ensure no scarcity pricing when such pricing is not consistent with market conditions. Scarcity pricing can serve two functions in wholesale power markets: revenue adequacy and price signals. Scarcity pricing for revenue adequacy, as in PJM's 2019 ORDC proposal, is not required in PJM. Scarcity pricing for price signals that reflect market conditions during periods of scarcity is required in PJM. Scarcity pricing is also part of an appropriate incentive structure facing both load and generation owners in a working wholesale electric power market design. Scarcity pricing must be designed to ensure that market prices reflect actual market conditions, that scarcity pricing occurs with transparent triggers based on measured reserve levels and transparent prices, that scarcity pricing only occurs when scarcity exists, that scarcity pricing not be excessive or punitive, and that there are strong incentives for competitive behavior and strong disincentives to exercise market power. Such administrative scarcity pricing is a key link between energy and capacity markets.

The PJM defined inputs to the dispatch tools, particularly the RT SCED, have substantial effects on energy market outcomes. Transmission line ratings, transmission penalty factors, load forecast bias, and hydro resource schedules change the dispatch of the system, affect prices, and can create significant price increases, particularly through transmission line limit violations. PJM operator interventions to reduce line ratings unnecessarily trigger transmission constraint penalty factors and significantly increase prices. Violations of the artificially reduced line limits had a direct effect on higher LMP in the first three months of 2023. If the line limits had not been artificially reduced for the PJM transmission constraints and everything else remained unchanged, fewer constraints would have been violated and the transmission penalty factor's contribution to the load weighted average LMP in the first three months of 2023 would have decreased by 99.1 percent from $0.75 to $0.01 per MWh. PJM should evaluate its interventions in the market, consider whether the interventions are appropriate, and provide greater transparency to enhance market efficiency.

Fast start pricing, implemented on September 1, 2021, has disconnected pricing from dispatch instructions and created a greater reliance on uplift rather than price as an incentive to follow PJM's instructions. The objective of efficient short run price signals is to minimize system production costs, not to minimize uplift. Repricing the market to reflect commitment costs using fast start pricing prioritizes minimizing uplift over minimizing production costs.[18] The tradeoff exists because when commitment costs are included in prices, the price signal no longer equals the short run marginal cost and therefore no longer provides the correct signal for efficient behavior for market participants making decisions on the margin, whether resources, load,

17 177 FERC ¶ 61,209 (2021).

18 See 173 FERC ¶ 61,244 (2020).

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

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

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

The three pivotal supplier test is applied by PJM on an ongoing basis for local energy markets in order to determine whether offer capping is required for transmission constraints.[19] However, there are some issues with the application of market power mitigation in the day-ahead energy market and the real-time energy market when market sellers fail the TPS test. The Commission recognized some of these issues in its order issued on June 17, 2021.[20] PJM continues to ignore the evidence cited by the Commission and denies the prevalence of these issues, instead of ensuring that market power mitigation works as intended and results in efficient market outcomes.[21] Many of these issues can be resolved by simple rule changes. The MMU proposed these rule changes in its response submitted on October 15, 2021, and continues to recommend them.[22] The MMU recommendations would shorten the solution time of the day-ahead market software, which would help facilitate enhanced combined cycle modelling. PJM proposes to weaken market power mitigation

19 The MMU reviews PJM's application of the TPS test and brings issues to the attention of PJM.
20 See 175 FERC ¶ 61,231 (2021).
21 *See* PJM. "Answer of PJM Interconnection L.L.C.," Docket No. EL21-78 (September 15, 2021).
22 *See* "Comments of the Independent Market Monitor for PJM," Docket No. EL21-78 (October 15, 2021).

as part of implementing the enhanced combined cycle modelling project. PJM's proposals would ensure that the identified issues with the implementation of market power mitigation in the energy market would never be addressed and would be exacerbated.

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

A competitive market requires that prices increase when fuel costs increase and that prices decrease when fuel costs decrease. A competitive market does not require that prices increase when markup increases or when PJM artificially triggers transmission constraint penalty factors. The overall energy market results support the conclusion that energy prices in PJM are set, generally, by marginal units operating at, or close to, their marginal costs, although this was not always the case in the first three months of 2023 or prior years. Given the structure of the energy market which can permit the exercise of aggregate and local market power, the change in some participants' behavior is a source of concern in the energy market and provides a reason to use correctly defined short run marginal cost as the sole basis for cost-based offers and a reason for implementing an aggregate market power test and correcting the offer capping process for resources with local market power. The MMU concludes that the PJM energy market results were competitive in the first three months of 2023.

Supply and Demand

Market Structure

Supply

Supply includes physical generation, imports and virtual transactions.

In the first three months of 2023, 146 MW of new resources were added in the energy market, and 0 MW of resources were retired.

Figure 3-1 shows real-time and day-ahead hourly supply curves in the winters of 2021/2022 and 2022/2023. [23] [24] The real-time supply curve includes hourly on peak average offers. The real-time supply curve includes available MW from units that are online or have a notification plus start time that is no more than one hour. The day-ahead supply curve shows all available hourly on peak average offers.

The real-time hourly on peak average offered supply was 148,236 MW in the winter of 2021/2022, and 141,798 MW in the winter of 2022/2023. The day-ahead hourly on peak average offered supply was 168,965 MW in the winter of 2021/2022, and 163,028 MW in the winter of 2022/2023.

23 Real-time supply includes real-time generation offers and import MWh.
24 The supply curve period is from December 1 to February 28.

Figure 3-1 Real-time and day-ahead hourly supply curves: Winter of 2021/2022 and 2022/2023

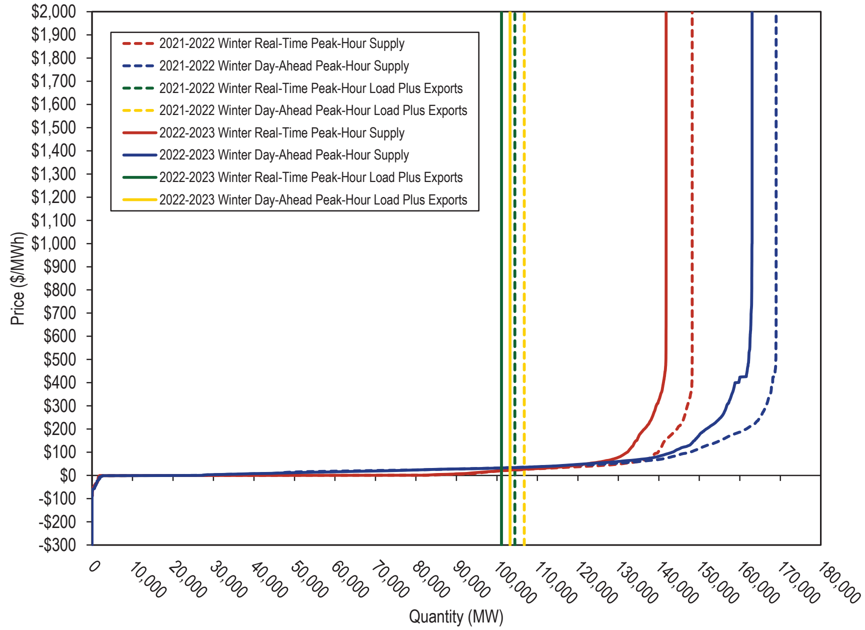


Figure 3-2 shows the typical dispatch range.

Figure 3-2 Typical dispatch range of supply curves

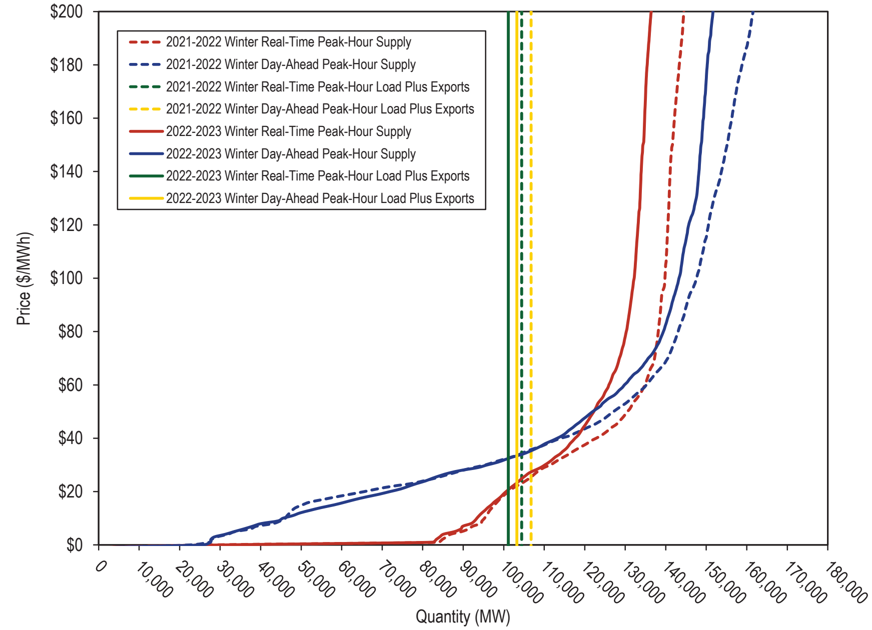


Table 3-2 shows the price elasticity of the real-time supply curve for the peak hours in the winter of 2021/2022 and 2022/2023 by load level.

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

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

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

Table 3-2 Price elasticity of the supply curve

	GW			
Winter	Min - 75	75 - 95	95 - 115	115 - Max
2018-2019	0.015	0.361	0.223	0.004
2019-2020	0.178	0.371	0.035	0.006
2020-2021	0.018	0.278	0.093	0.006
2021-2022	0.016	0.076	0.233	0.007
2022-2023	0.013	0.140	0.038	0.009

Real-Time Supply

The real-time hourly average cleared generation in the first three months of 2023 decreased by 5.7 percent from the first three months of 2022, from 98,506 MWh to 92,936 MWh.[25]

The real-time hourly average cleared supply including imports in the first three months of 2023 decreased by 5.5 percent from the first three months of 2022, from 100,535 MWh to 94,971 MWh.

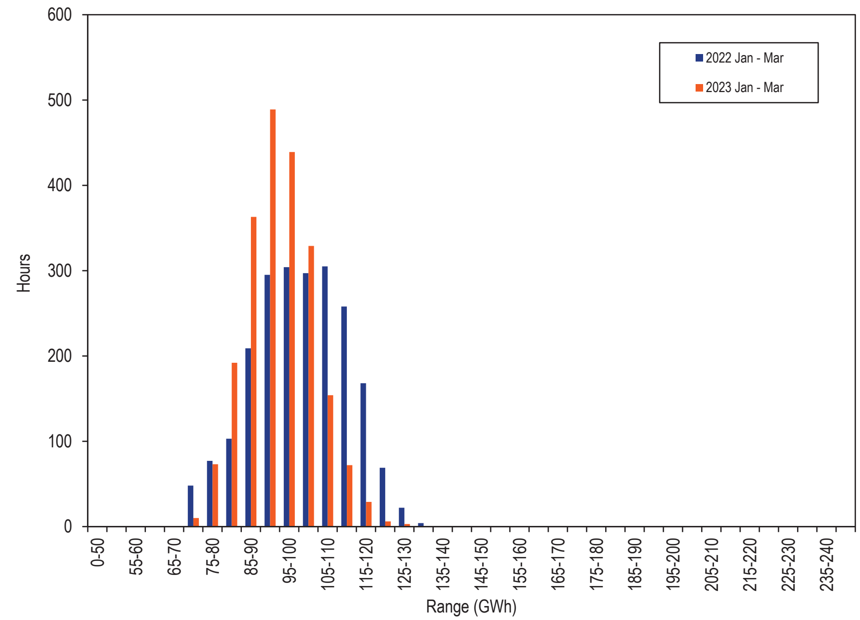
In the PJM Real-Time Energy Market, there are three types of supply offers:

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

PJM Real-Time Supply Frequency

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

Figure 3-3 Distribution of real-time generation plus imports: January through March, 2022 and 2023[26]



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

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

PJM Real-Time Average Supply

Table 3-3 shows the real-time hourly average supply and its standard deviation for the first three months of 2001 through 2023. The real-time hourly average cleared generation in the first three months of 2023 decreased by 5.7 percent from the first three months of 2022, from 98,506 MWh to 92,936 MWh.

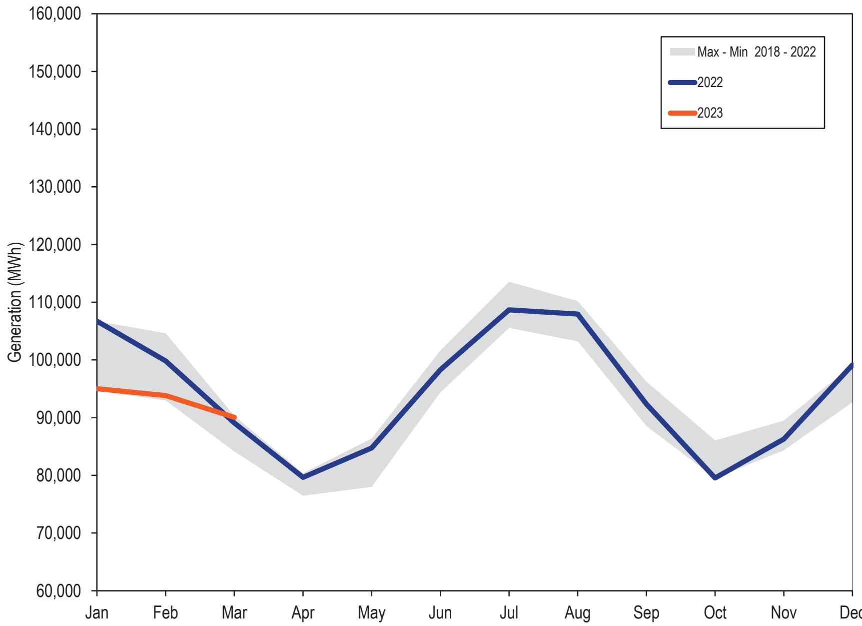
Table 3-3 Real-time hourly average generation and generation plus imports: January through March, 2001 through 2023

	PJM Real-Time Supply (MWh)				Year-to-Year Change			
	Generation		Generation Plus Imports		Generation		Generation Plus Imports	
Jan-Mar	Generation	Standard Deviation	Supply	Standard Deviation	Generation	Standard Deviation	Supply	Standard Deviation
2001	30,923	3,488	33,806	3,358	NA	NA	NA	NA
2002	27,948	3,416	31,465	3,508	(9.6%)	(2.1%)	(6.9%)	4.5%
2003	38,731	5,187	42,498	5,092	38.6%	51.8%	35.1%	45.2%
2004	37,790	4,660	41,960	4,899	(2.4%)	(10.2%)	(1.3%)	(3.8%)
2005	74,187	8,269	80,184	9,017	96.3%	77.4%	91.1%	84.1%
2006	82,550	7,921	87,729	8,565	11.3%	(4.2%)	9.4%	(5.0%)
2007	86,286	10,018	91,454	11,351	4.5%	26.5%	4.2%	32.5%
2008	86,690	9,375	92,075	10,150	0.5%	(6.4%)	0.7%	(10.6%)
2009	81,987	11,417	88,148	12,213	(5.4%)	21.8%	(4.3%)	20.3%
2010	81,676	12,801	87,009	13,236	(0.4%)	12.1%	(1.3%)	8.4%
2011	83,505	10,116	88,750	10,884	2.2%	(21.0%)	2.0%	(17.8%)
2012	88,068	11,177	93,128	11,685	5.5%	10.5%	4.9%	7.4%
2013	92,776	10,030	98,002	10,812	5.3%	(10.3%)	5.2%	(7.5%)
2014	100,655	12,427	106,879	13,255	8.5%	23.9%	9.1%	22.6%
2015	97,741	13,085	105,027	14,351	(2.9%)	5.3%	(1.7%)	8.3%
2016	88,470	12,666	94,383	13,890	(9.5%)	(3.2%)	(10.1%)	(3.2%)
2017	91,076	11,009	94,390	11,673	2.9%	(13.1%)	0.0%	(16.0%)
2018	95,491	13,151	98,199	14,058	4.8%	19.5%	4.0%	20.4%
2019	97,010	12,379	98,828	12,777	1.6%	(5.9%)	0.6%	(9.1%)
2020	90,675	9,852	91,698	9,992	(6.5%)	(20.4%)	(7.2%)	(21.8%)
2021	96,005	12,057	97,075	12,432	5.9%	22.4%	5.9%	24.4%
2022	98,506	11,686	100,535	12,196	2.6%	(3.1%)	3.6%	(1.9%)
2023	92,936	8,404	94,971	8,836	(5.7%)	(28.1%)	(5.5%)	(27.6%)

PJM Real-Time Monthly Average Generation

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

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



Day-Ahead Supply

The day-ahead hourly average supply in the first three months of 2023, including INCs and UTCs, increased by 7.3 percent from the first three months of 2022, from 113,169 MWh to 121,433 MWh.

The day-ahead hourly average supply in the first three months of 2023, including INCs, UTCs and exports, increased by 7.6 percent from the first three months of 2022, from 113,410 MWh to 122,016 MWh.

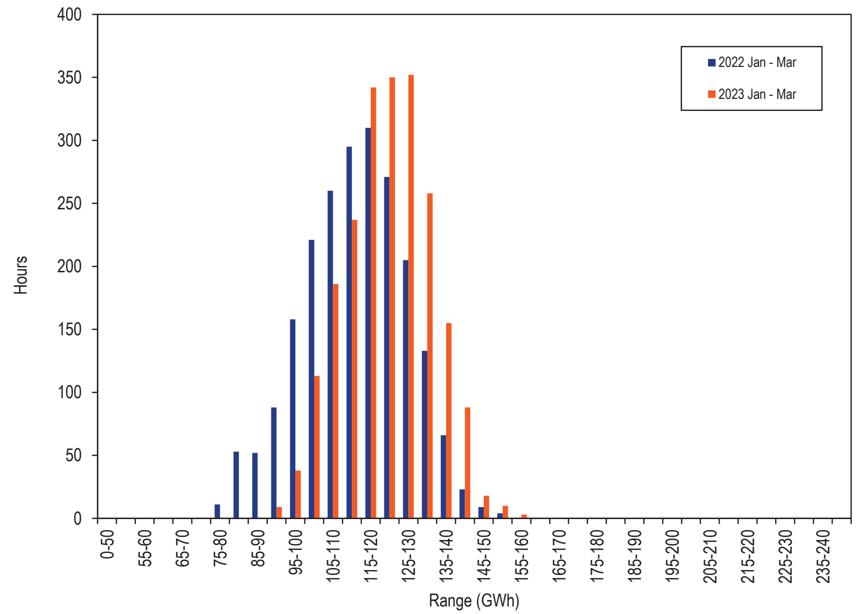
In the PJM Day-Ahead Energy Market, there are five types of financially binding supply offers:

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

PJM Day-Ahead Supply Duration

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

Figure 3-5 Distribution of day-ahead cleared supply plus imports: January through March, 2022 and 2023[27]



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

PJM Day-Ahead Average Supply

Table 3-4 presents day-ahead hourly cleared supply summary statistics for each year from the first three months of 2001 through 2023. The day-ahead hourly average supply in the first three months of 2023, including INCs and UTCs, increased by 7.3 percent from the first three months of 2022, from 113,169 MWh to 121,433 MWh.

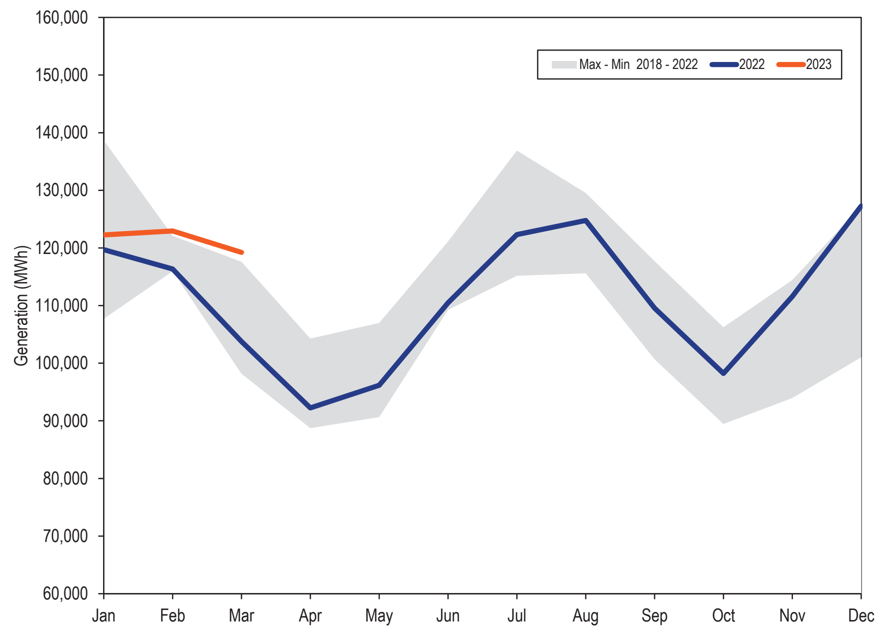
Table 3-4 Day-ahead hourly average cleared supply and cleared supply plus imports: January through March, 2001 through 2023

	PJM Day-Ahead Supply (MWh)				Year-to-Year Change			
	Supply		Supply Plus Imports		Supply		Supply Plus Imports	
Jan-Mar	Supply	Standard Deviation	Supply	Standard Deviation	Supply	Standard Deviation	Supply	Standard Deviation
2001	28,494	2,941	29,252	3,021	NA	NA	NA	NA
2002	20,274	10,131	20,827	10,134	(28.8%)	244.5%	(28.8%)	235.5%
2003	37,147	4,337	37,807	4,389	83.2%	(57.2%)	81.5%	(56.7%)
2004	46,591	4,794	47,377	5,039	25.4%	10.5%	25.3%	14.8%
2005	89,011	9,434	90,502	9,443	91.0%	96.8%	91.0%	87.4%
2006	97,319	9,035	99,551	9,061	9.3%	(4.2%)	10.0%	(4.0%)
2007	110,099	11,938	112,561	12,141	13.1%	32.1%	13.1%	34.0%
2008	109,711	10,479	112,165	10,671	(0.4%)	(12.2%)	(0.4%)	(12.1%)
2009	104,880	13,895	107,325	14,031	(4.4%)	32.6%	(4.3%)	31.5%
2010	101,733	13,835	104,858	13,917	(3.0%)	(0.4%)	(2.3%)	(0.8%)
2011	110,310	12,200	112,854	12,419	8.4%	(11.8%)	7.6%	(10.8%)
2012	132,178	13,701	134,405	13,804	19.8%	12.3%	19.1%	11.2%
2013	147,246	13,054	149,300	13,244	11.4%	(4.7%)	11.1%	(4.1%)
2014	168,373	11,875	170,778	11,935	14.3%	(9.0%)	14.4%	(9.9%)
2015	123,431	14,671	125,980	14,916	(26.7%)	23.5%	(26.2%)	25.0%
2016	133,199	19,049	135,574	19,349	7.9%	29.8%	7.6%	29.7%
2017	140,771	16,923	142,094	16,938	5.7%	(11.2%)	4.8%	(12.5%)
2018	120,754	22,172	121,313	22,177	(14.2%)	31.0%	(14.6%)	30.9%
2019	122,368	13,778	122,865	13,822	1.3%	(37.9%)	1.3%	(37.7%)
2020	112,939	12,020	113,274	12,021	(7.7%)	(12.8%)	(7.8%)	(13.0%)
2021	107,588	13,940	107,851	14,003	(4.7%)	16.0%	(4.8%)	16.5%
2022	113,169	13,544	113,410	13,615	5.2%	(2.8%)	5.2%	(2.8%)
2023	121,433	11,143	122,016	11,274	7.3%	(17.7%)	7.6%	(17.2%)

PJM Day-Ahead Monthly Average Cleared Supply

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

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



Real-Time and Day-Ahead Supply

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

The total physical day-ahead average generation less the total physical real-time average generation in the first three months of 2023 decreased 1,014 MWh from the first three months of 2022, from 784 MWh to -229 MWh. The total day-ahead average supply less the total real-time average supply in the first three months of 2023 increased 14,170 MWh from the first three months of 2022, from 12,876 MWh to 27,046 MWh, primarily as a result of the increase in UTCs.

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

		Day-Ahead					Real-Time		Day-Ahead Less Real-Time	
	Jan-Mar	Generation	INC Offers	Up to Congestion	Imports	Total Supply	Generation	Total Supply	Generation	Supply
Average	2022	99,290	3,565	10,314	241	113,410	98,506	100,535	784	12,876
	2023	92,707	4,465	24,262	584	122,016	92,936	94,971	(229)	27,046
Median	2022	99,449	3,433	9,735	171	113,949	98,783	100,746	665	13,203
	2023	92,330	4,390	23,587	556	122,244	92,557	94,586	(227)	27,658
Standard Deviation	2022	13,291	1,212	3,262	222	13,615	11,686	12,196	1,605	1,419
	2023	9,356	1,406	5,475	310	11,274	8,404	8,836	952	2,439
Peak Average	2022	103,706	3,909	11,115	220	118,950	102,738	104,704	969	14,245
	2023	97,390	5,131	25,346	627	128,494	97,407	99,560	(17)	28,933
Peak Median	2022	103,419	3,836	10,441	136	118,894	102,442	104,643	977	14,252
	2023	96,389	5,136	24,376	597	128,348	96,839	99,158	(450)	29,190
Peak Standard Deviation	2022	11,727	1,216	3,205	224	11,455	10,068	10,609	1,660	846
	2023	7,875	1,360	5,197	313	8,498	6,868	7,272	1,007	1,226
Off-Peak Average	2022	95,306	3,255	9,592	260	108,413	94,688	96,773	618	11,640
	2023	88,482	3,864	23,284	544	116,173	88,902	90,830	(421)	25,343
Off-Peak Median	2022	95,405	3,138	9,002	200	109,043	95,160	97,158	245	11,885
	2023	87,884	3,771	22,964	533	115,619	88,295	90,151	(411)	25,468
Off-Peak Standard Deviation	2022	13,363	1,123	3,143	219	13,479	11,734	12,316	1,630	1,163
	2023	8,542	1,152	5,536	301	10,231	7,584	8,042	958	2,189

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

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

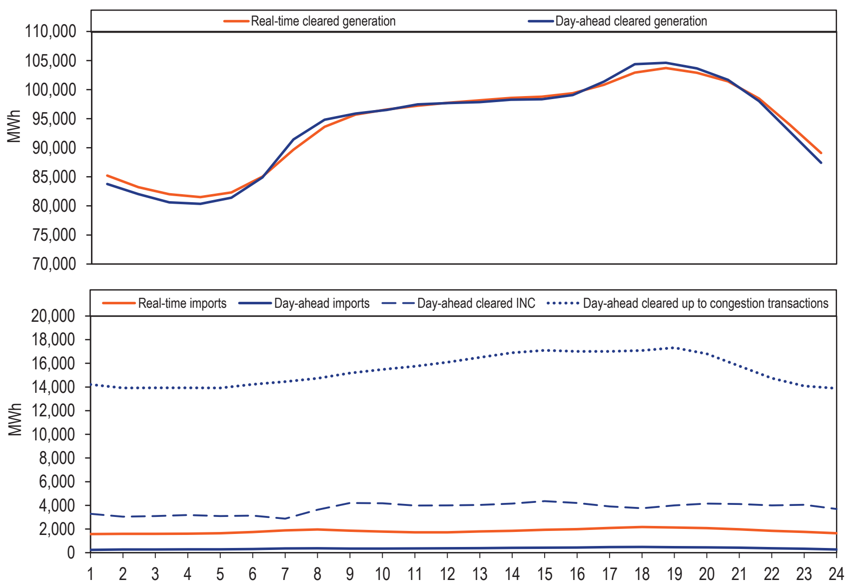
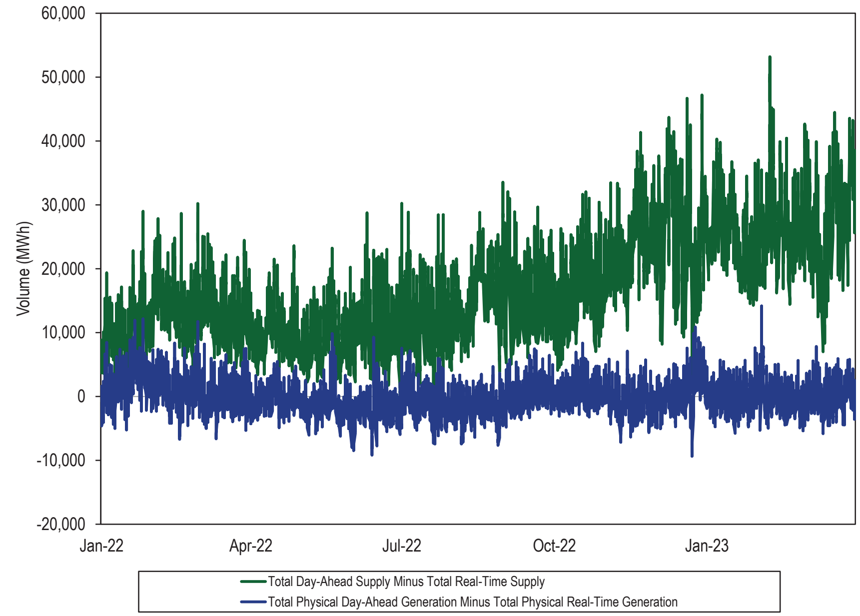


Figure 3-8 shows the difference between day-ahead and real-time daily average supply in 2022 and the first three months of 2023.

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



Demand

Demand includes physical load and exports and virtual transactions.

Peak Demand

In this section, demand refers to accounting load and exports, and in the day-ahead energy market, includes virtual transactions.[28]

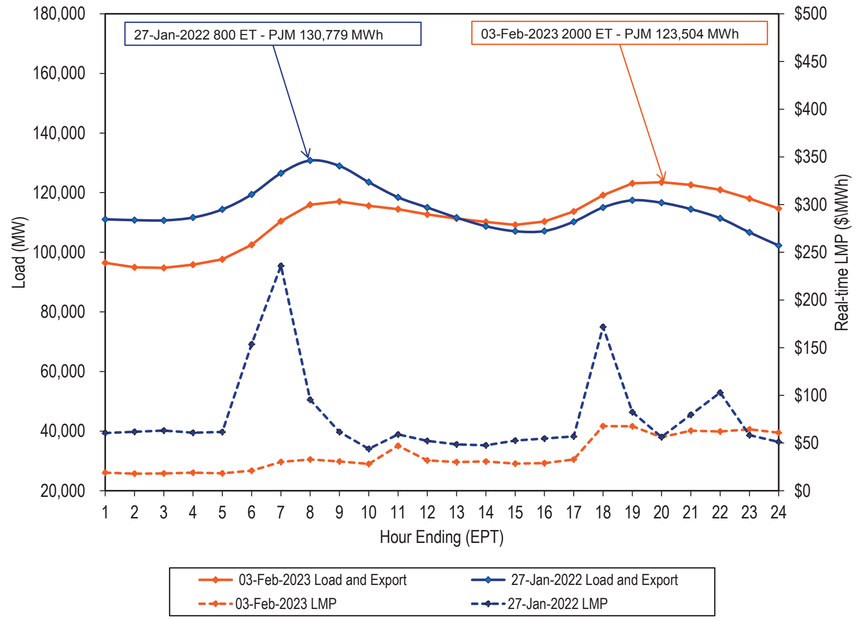
Table 3-6 shows the peak load plus exports for the first three months of 2009 through 2023. The real-time hourly peak load plus exports in the first three months of 2023 was 123,504 MWh (117,705 MWh of load plus 5,798 MWh of gross exports) in the HE 2000 (EPT) on February 03, 2023, which was 5.6 percent, 7,276 MWh, lower than the PJM peak load plus exports in the first three months of 2022, which was 130,779 MWh in the HE 0800 (EPT) on January 27, 2022.

Table 3-6 Actual footprint peak load plus export: January through March, 2009 through 2023[29] [30]

Jan - Mar	Date	Hour Ending (EPT)	PJM Load Plus Export (MWh)	Annual Change (MWh)	Annual Change (%)
2009	Fri, January 16	9	128,310	NA	NA
2010	Mon, January 04	19	120,792	(7,517)	(5.9%)
2011	Mon, January 24	8	121,682	889	0.7%
2012	Wed, January 04	8	133,618	11,936	9.8%
2013	Tue, January 22	20	127,558	(6,060)	(4.5%)
2014	Tue, January 07	9	140,946	13,388	10.5%
2015	Fri, February 20	8	144,850	3,904	2.8%
2016	Tue, January 19	8	131,506	(13,344)	(9.2%)
2017	Mon, January 09	9	129,777	(1,729)	(1.3%)
2018	Fri, January 05	19	137,942	8,165	6.3%
2019	Wed, January 30	20	140,037	2,096	1.5%
2020	Wed, January 22	8	122,162	(17,875)	(12.8%)
2021	Wed, February 17	9	126,546	4,385	3.6%
2022	Thu, January 27	8	130,779	4,233	3.3%
2023	Fri, February 03	20	123,504	(7,276)	(5.6%)

Figure 3-9 compares prices and demand on the peak load days for the first three months of 2022 and 2023. The real-time average LMP for January 27, 2022, peak load hour was $95.54 per MWh, and for February 3, 2023, peak load hour it was $56.22 per MWh.

Figure 3-9 Peak load and export day comparison



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

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

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

Real-Time Demand

The real-time hourly average load in the first three months of 2023 decreased by 5.1 percent from the first three months of 2022, from 92,007 MWh to 87,311 MWh.[31]

The real-time hourly average demand including exports in the first three months of 2023 decreased by 5.3 percent from the first three months of 2022, from 98,417 MWh to 93,209 MWh.

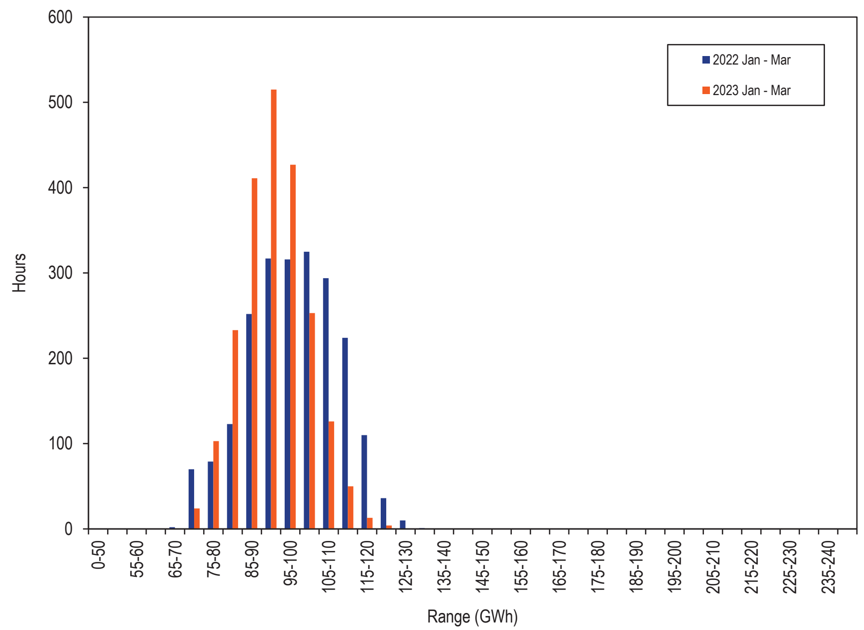
In the PJM Real-Time Energy Market, there are two types of demand:

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

PJM Real-Time Demand Duration

Figure 3-10 shows the distribution of the real-time hourly load plus exports for the first three months of 2022 and 2023.[32]

Figure 3-10 Distribution of real-time load plus exports: January through March, 2022 and 2023[33]



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

32 All real-time load data in Section 3, "Energy Market," "Market Performance: Load and LMP," are based on PJM accounting load. See the *Technical Reference for PJM Markets*, "Load Definitions," for detailed definitions of accounting load. <http://www.monitoringanalytics.com/reports/Technical_References/references.shtml>.

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

PJM Real-Time Average Load

Table 3-7 presents real-time hourly demand summary statistics for 2001 through 2022.[34] The real-time hourly average load in the first three months of 2023 decreased by 5.1 percent from the first three months of 2022, from 92,007 MWh to 87,311 MWh.

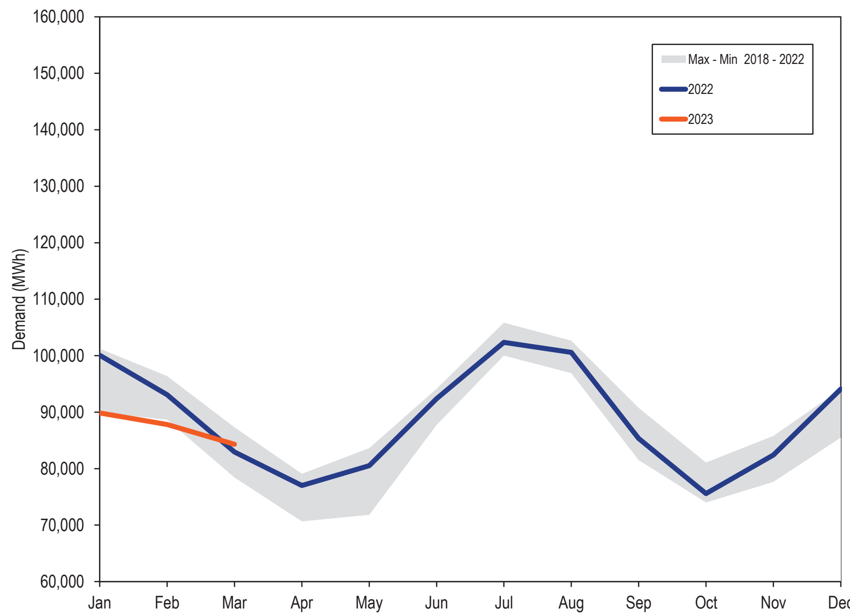
Table 3-7 Real-time hourly average load and load plus exports: January through March, 2001 through 2023

	PJM Real-Time Demand (MW)				Year to Year Change			
	Load		Load Plus Exports		Load		Load Plus Exports	
Jan-Mar	Load	Standard Deviation	Demand	Standard Deviation	Load	Standard Deviation	Demand	Standard Deviation
2001	31,254	3,846	33,452	3,704	NA	NA	NA	NA
2002	29,968	4,083	30,988	3,932	(4.1%)	6.1%	(7.4%)	6.1%
2003	39,249	5,546	41,600	5,701	31.0%	35.8%	34.2%	45.0%
2004	39,549	5,761	41,198	5,394	0.8%	3.9%	(1.0%)	(5.4%)
2005	71,388	8,966	79,319	9,587	80.5%	55.6%	92.5%	77.8%
2006	80,179	8,977	86,567	9,378	12.3%	0.1%	9.1%	(2.2%)
2007	84,586	12,040	90,304	12,012	5.5%	34.1%	4.3%	28.1%
2008	82,235	10,184	89,092	10,621	(2.8%)	(15.4%)	(1.3%)	(11.6%)
2009	81,170	11,718	86,110	11,948	(1.3%)	15.1%	(3.3%)	12.5%
2010	81,121	10,694	86,843	11,262	(0.1%)	(8.7%)	0.9%	(5.7%)
2011	81,018	10,273	86,635	10,613	(0.1%)	(3.9%)	(0.2%)	(5.8%)
2012	86,329	10,951	91,090	11,293	6.6%	6.6%	5.1%	6.4%
2013	91,337	10,610	95,835	10,452	5.8%	(3.1%)	5.2%	(7.4%)
2014	98,317	13,484	104,454	12,843	7.6%	27.1%	9.0%	22.9%
2015	97,936	13,445	102,821	13,855	(0.4%)	(0.3%)	(1.6%)	7.9%
2016	89,322	13,262	92,777	13,409	(8.8%)	(1.4%)	(9.8%)	(3.2%)
2017	87,598	11,208	92,791	11,295	(1.9%)	(15.5%)	0.0%	(15.8%)
2018	92,761	13,244	96,216	13,487	5.9%	18.2%	3.7%	19.4%
2019	91,962	11,888	96,898	12,373	(0.9%)	(10.2%)	0.7%	(8.3%)
2020	85,608	10,004	90,093	9,736	(6.9%)	(15.8%)	(7.0%)	(21.3%)
2021	89,887	11,000	95,236	12,103	5.0%	10.0%	5.7%	24.3%
2022	92,007	11,782	98,417	11,698	2.4%	7.1%	3.3%	(3.3%)
2023	87,311	8,638	93,209	8,547	(5.1%)	(26.7%)	(5.3%)	(26.9%)

PJM Real-Time Monthly Average Load

Figure 3-11 compares the real-time monthly average load plus exports in the first three months of 2022 and 2023, with the historic five year range. In January and February of 2023, the monthly average load plus exports was lower than the minimum of the past five years, primarily as a result of mild winter weather.

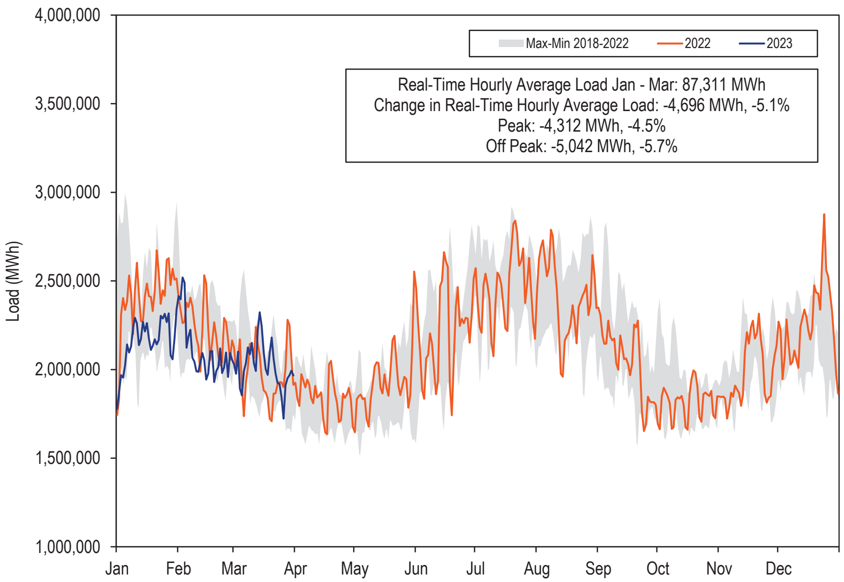
Figure 3-11 Real-time monthly average hourly load plus exports: 2022 through March 2023



34 Accounting load is used because accounting load is the load customers pay for in PJM settlements. The use of accounting load with losses before June 1, and without losses after June 1, 2007, is consistent with PJM's calculation of LMP. Before June 1, 2007, transmission losses were included in accounting load. After June 1, 2007, transmission losses were excluded from accounting load and losses were addressed through the incorporation of marginal loss pricing in LMP.

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

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



The real-time load is significantly affected by weather conditions. Table 3-8 compares the monthly heating and cooling degree days in the first three months of 2022 and 2023.[35] Heating degree days decreased 22.0 percent compared to the first three months of 2022.

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

	2022		2023		Percent Change	
	Heating Degree Days	Cooling Degree Days	Heating Degree Days	Cooling Degree Days	Heating Degree Days	Cooling Degree Days
Jan	983	0	623	0	(36.6%)	0.0%
Feb	693	0	521	0	(24.8%)	0.0%
Mar	445	0	510	0	14.5%	0.0%
Apr	256	5				
May	21	101				
Jun	0	260				
Jul	0	406				
Aug	0	345				
Sep	15	153				
Oct	164	0				
Nov	386	3				
Dec	752	0				
Jan-Mar	2,121	0	1,654	0	(22.0%)	0.0%

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

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

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

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

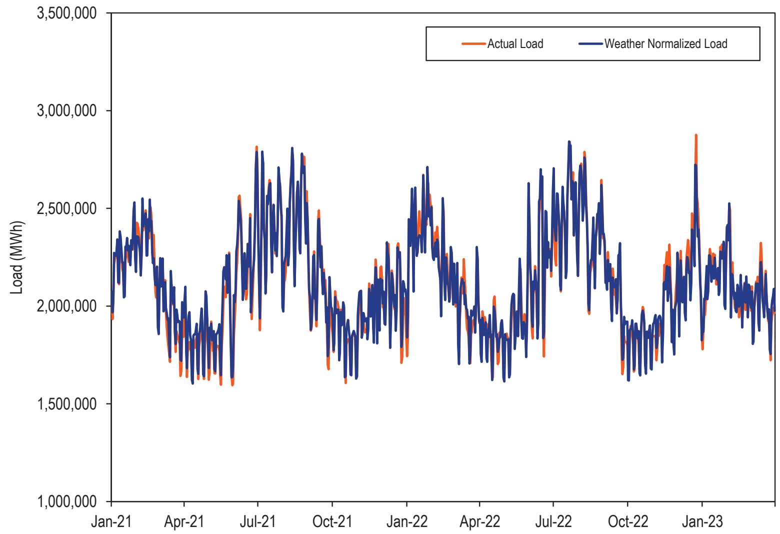


Table 3-9 compares the monthly actual load and the weather normalized load. Actual load was 0.3 percent higher than weather normalized load in the first three months of 2023, actual load was 0.4 percent higher than weather normalized load in the first three months of 2022, and actual load was 0.7 percent lower than weather normalized load in the first three months of 2021.

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

	2021			2022			2023		
	Actual Load	Weather Normalized Load	Percent Difference	Actual Load	Weather Normalized Load	Percent Difference	Actual Load	Weather Normalized Load	Percent Difference
Jan	69,303,496	69,689,108	(0.6%)	74,457,669	73,965,891	0.7%	66,854,012	66,649,610	0.3%
Feb	64,761,103	64,275,946	0.8%	62,556,707	61,833,819	1.2%	59,004,070	58,958,396	0.1%
Mar	60,002,018	61,459,726	(2.4%)	61,629,282	61,986,274	(0.6%)	62,646,982	62,266,981	0.6%
Apr	54,010,529	55,580,210	(2.8%)	55,444,404	55,267,453	0.3%			
May	57,460,157	59,183,412	(2.9%)	59,904,861	59,795,738	0.2%			
Jun	67,779,457	68,488,450	(1.0%)	66,521,445	67,334,205	(1.2%)			
Jul	74,409,489	74,488,509	(0.1%)	76,153,249	76,721,135	(0.7%)			
Aug	76,383,295	76,161,192	0.3%	74,839,426	74,939,704	(0.1%)			
Sep	62,305,584	62,675,810	(0.6%)	61,451,519	62,081,806	(1.0%)			
Oct	57,511,887	57,304,504	0.4%	56,233,707	56,324,880	(0.2%)			
Nov	59,887,527	59,557,389	0.6%	59,428,403	59,060,319	0.6%			
Dec	63,610,554	64,276,557	(1.0%)	70,003,632	68,138,490	2.7%			
Jan - Mar	194,066,617	195,424,781	(0.7%)	198,643,658	197,785,984	0.4%	188,505,064	187,874,988	0.3%

Day-Ahead Demand

The day-ahead hourly average demand in the first three months of 2023, including DECs and UTCs, increased by 8.2 percent from the first three months of 2022, from 106,845 MWh to 115,558 MWh.

The day-ahead hourly average demand in the first three months of 2023, including DECs, UTCs and exports, increased by 7.5 percent from the first three months of 2022, from 111,085 MWh to 119,435 MWh.

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

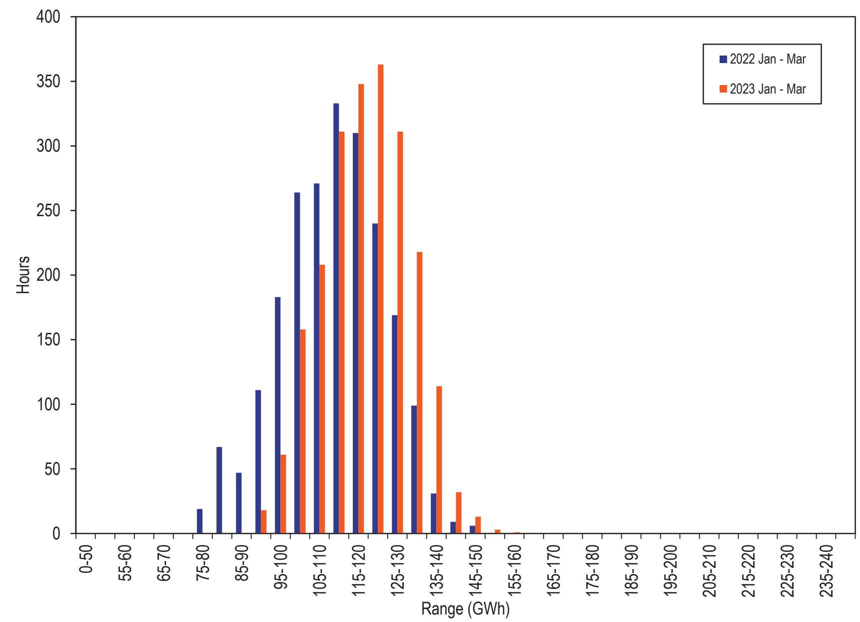
- **Fixed-Demand Bid.** Bid to purchase a defined MWh level of energy, regardless of LMP.
- **Price-Sensitive Bid.** Bid to purchase a defined MWh level of energy only up to a specified LMP, above which the load bid is zero.
- **Decrement Bid (DEC).** Financial bid to purchase a defined MWh level of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

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

PJM Day-Ahead Demand Duration

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

Figure 3-14 Distribution of day-ahead demand plus exports: January through March, 2022 and 2023[36]



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

PJM Day-Ahead Average Demand

Table 3-10 shows day-ahead hourly average demand for the first three months of 2001 through 2023. The day-ahead hourly average demand in the first three months of 2023, including DECs and UTCs, increased by 8.2 percent from the first three months of 2022, from 106,845 MWh to 115,558 MWh.

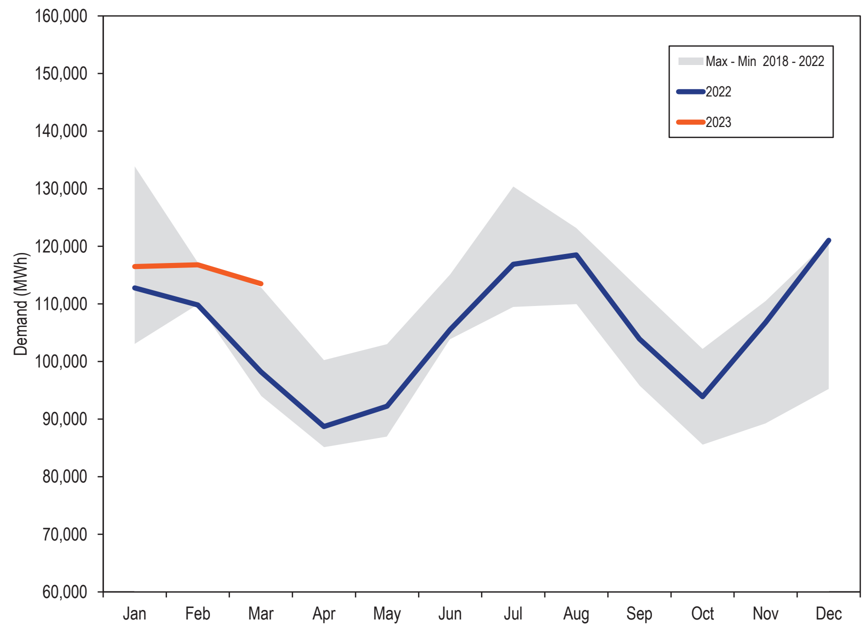
Table 3-10 Day-ahead hourly average demand and demand plus exports: January through March, 2001 through 2023

	PJM Day-Ahead Demand (MWh)				Year to Year Change			
	Demand		Demand Plus Exports		Demand		Demand Plus Exports	
Jan-Mar	Demand	Standard Deviation	Demand	Standard Deviation	Demand	Standard Deviation	Demand	Standard Deviation
2001	33,731	4,557	34,523	4,390	NA	NA	NA	NA
2002	33,976	4,960	34,004	4,964	0.7%	8.8%	(1.5%)	13.1%
2003	47,034	6,841	47,147	6,853	38.4%	37.9%	38.7%	38.1%
2004	46,885	5,591	47,123	5,537	(0.3%)	(18.3%)	(0.1%)	(19.2%)
2005	87,341	9,810	90,288	9,947	86.3%	75.5%	91.6%	79.6%
2006	96,244	9,453	99,342	9,777	10.2%	(3.6%)	10.0%	(1.7%)
2007	108,699	12,601	111,831	12,746	12.9%	33.3%	12.6%	30.4%
2008	105,995	10,677	109,428	10,975	(2.5%)	(15.3%)	(2.1%)	(13.9%)
2009	102,366	13,619	105,023	13,758	(3.4%)	27.6%	(4.0%)	25.4%
2010	101,012	11,937	104,866	12,103	(1.3%)	(12.4%)	(0.1%)	(12.0%)
2011	107,116	11,890	110,865	12,157	6.0%	(0.4%)	5.7%	0.4%
2012	129,258	13,163	132,757	13,481	20.7%	10.7%	19.7%	10.9%
2013	143,585	13,120	146,878	13,108	11.1%	(0.3%)	10.6%	(2.8%)
2014	163,031	11,914	167,318	11,717	13.5%	(9.2%)	13.9%	(10.6%)
2015	119,084	14,227	123,115	14,573	(27.0%)	19.4%	(26.4%)	24.4%
2016	130,469	18,627	133,137	18,806	9.6%	30.9%	8.1%	29.0%
2017	135,574	16,264	139,299	16,454	3.9%	(12.7%)	4.6%	(12.5%)
2018	116,635	21,378	119,023	21,606	(14.0%)	31.4%	(14.6%)	31.3%
2019	117,251	13,075	120,386	13,423	0.5%	(38.8%)	1.1%	(37.9%)
2020	108,144	11,625	111,101	11,658	(7.8%)	(11.1%)	(7.7%)	(13.1%)
2021	102,372	12,828	105,639	13,599	(5.3%)	10.4%	(4.9%)	16.6%
2022	106,845	12,933	111,085	13,085	4.4%	0.8%	5.2%	(3.8%)
2023	115,558	10,827	119,435	10,914	8.2%	(16.3%)	7.5%	(16.6%)

PJM Day-Ahead Monthly Average Demand

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

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



Real-Time and Day-Ahead Demand

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

The total physical day-ahead average load less the total physical real-time average load in the first three months of 2023 increased 977 MWh from the first three months of 2022, from -1,533 MWh to -555 MWh. The total day-ahead average demand less the total real-time average demand in the first three months of 2023 increased 13,559 MWh from the first three months of 2022, from 12,667 MWh to 26,226 MWh.

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

		Day-Ahead						Real-Time		Day-Ahead Less Real-Time	
Jan-Mar	Year	Fixed Demand	Price Sensitive	DEC Bids	Up-to Congestion	Exports	Total Demand	Load	Total Demand	Load	Demand
Average	2022	89,381	1,094	6,056	10,314	4,240	111,085	92,007	98,417	(1,533)	12,667
	2023	86,239	517	4,540	24,262	3,877	119,435	87,311	93,209	(555)	26,226
Median	2022	89,829	1,112	5,823	9,735	4,211	111,616	92,241	98,733	(1,300)	12,883
	2023	86,182	562	4,326	23,587	3,874	119,728	87,085	92,869	(342)	26,859
Standard Deviation	2022	11,377	180	1,699	3,262	691	13,085	11,782	11,698	(225)	1,387
	2023	8,422	227	1,487	5,475	866	10,914	8,638	8,547	11	2,366
Peak Average	2022	93,742	1,185	6,155	11,115	4,347	116,543	95,963	102,513	(1,036)	14,030
	2023	90,856	569	5,079	25,346	3,960	125,810	91,651	97,730	(226)	28,080
Peak Median	2022	93,981	1,192	6,005	10,441	4,277	116,528	96,008	102,547	(835)	13,981
	2023	90,099	592	4,968	24,376	3,983	125,666	91,226	97,338	(535)	28,328
Peak Standard Deviation	2022	9,708	151	1,678	3,205	684	10,975	10,171	10,136	(313)	839
	2023	6,547	251	1,427	5,197	919	8,167	7,059	6,998	(261)	1,169
Off-Peak Average	2022	85,446	1,012	5,966	9,592	4,144	106,160	88,439	94,722	(1,981)	11,438
	2023	82,074	470	4,054	23,284	3,803	113,684	83,396	89,130	(853)	24,554
Off-Peak Median	2022	85,716	1,017	5,669	9,002	4,141	106,836	88,925	95,268	(2,192)	11,568
	2023	81,965	517	3,809	22,964	3,810	113,133	83,030	88,550	(548)	24,583
Off-Peak Standard Deviation	2022	11,341	165	1,713	3,143	684	12,884	11,999	11,786	(493)	1,097
	2023	7,726	192	1,368	5,536	808	9,833	8,043	7,729	(125)	2,104

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

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

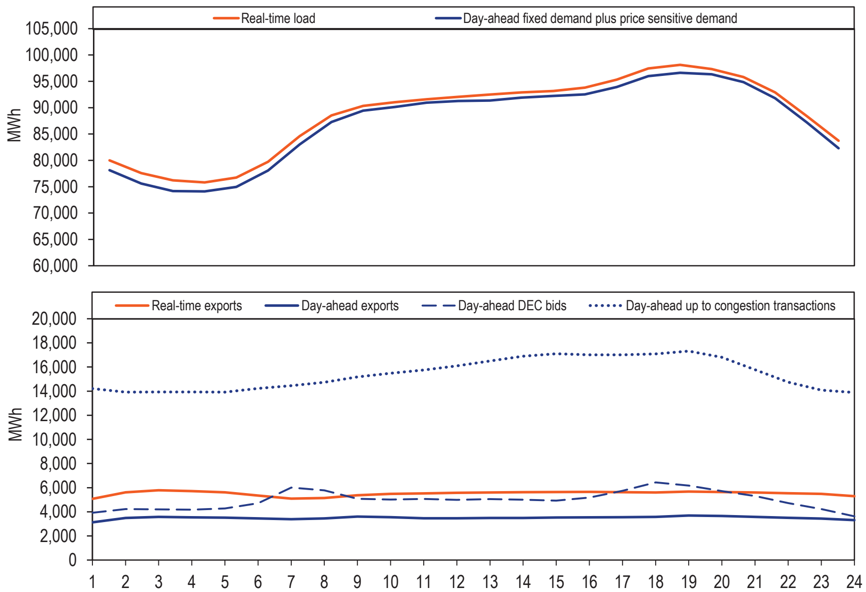
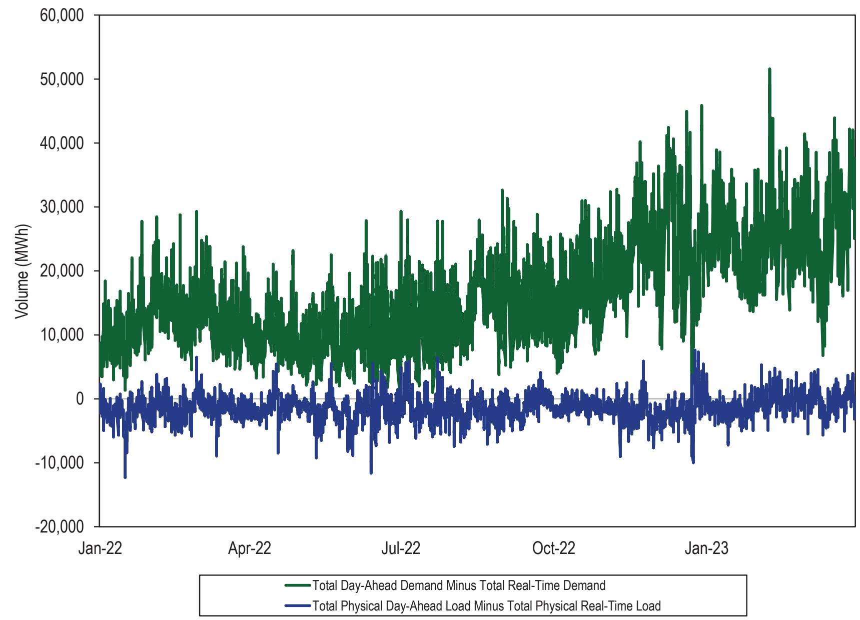


Figure 3-17 shows the difference between the day-ahead and real-time daily average demand in the first three months of 2022 and 2023.

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



Market Behavior

Generator Offers

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

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

Units may designate all or a portion of their capacity as emergency MW. Table 3-12 shows that 0.7 percent of offered MW are emergency MW. In some cases, higher shares of emergency MW result from offer behavior that does not accurately represent the availability of the emergency MW in real time.

In the day-ahead market in the first three months of 2023, 23.0 percent of MW were offered as must run, 31.6 percent of MW were offered as the economic minimum MW for dispatchable units, 44.7 percent of MW were offered as dispatchable, and 0.7 percent of MW were offered as emergency maximum MW.

In the first three months of 2023, 50.4 percent of offer MW were priced below $50 per MWh, compared to 61.1 percent in the first three months of 2022. Higher fuel prices, emissions prices, opportunity costs for emissions limited resources, and markup all contributed to higher offers in the first three months of 2023.

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

			Dispatchable Range											
Unit Type	Must Run	Eco Min	($300) - $0	$0 - $25	$25 - $50	$50 - $75	$75 - $100	$100 - $200	$200 - $400	$400 - $600	$600 - $800	$800 - $1000	Emergency MW	Dispatchable Percent
CC	8.4%	35.4%	0.1%	9.0%	21.2%	11.7%	4.7%	6.1%	2.9%	0.2%	0.1%	0.0%	0.2%	56.0%
CT	0.4%	56.8%	0.0%	0.2%	4.7%	7.3%	6.3%	10.2%	9.7%	2.0%	0.5%	0.1%	1.7%	41.1%
Diesel	0.0%	91.8%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	8.2%	0.0%	0.0%	0.0%	0.0%	8.2%
Hydro	84.0%	0.0%	15.9%	0.0%	-0.0%	0.0%	-0.0%	0.0%	-0.0%	0.0%	-0.0%	-0.0%	0.0%	16.0%
Nuclear	89.8%	6.7%	2.5%	1.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	3.5%
Solar	14.9%	1.2%	75.6%	1.9%	1.6%	1.0%	1.0%	2.1%	0.6%	0.0%	0.0%	0.0%	0.0%	83.8%
Steam - Coal	26.4%	25.6%	0.0%	3.5%	17.3%	9.2%	6.9%	6.2%	1.3%	2.0%	0.0%	0.0%	1.6%	46.5%
Steam - Other	5.1%	22.6%	1.2%	1.8%	8.8%	8.8%	10.6%	15.8%	21.5%	3.1%	0.0%	0.1%	0.4%	71.8%
Wind	4.5%	0.8%	83.1%	5.7%	3.2%	1.2%	0.6%	0.5%	0.3%	0.0%	0.0%	0.1%	0.0%	94.7%
Other	16.3%	47.8%	5.1%	1.0%	5.5%	3.4%	0.2%	1.2%	15.1%	1.1%	0.2%	0.0%	3.2%	32.7%
All Units	23.0%	31.6%	2.5%	4.2%	12.1%	7.9%	5.0%	6.6%	5.1%	1.1%	0.1%	0.0%	0.7%	44.7%

Hourly Offers and Intraday Offer Updates

All participants may make hourly offers. Participants must opt in on a monthly basis to make intraday offer updates. Participants that have opted in can make updates only based on the process defined in their fuel cost policies. Table 3-13 shows the daily average number of units that make hourly offers, that opted in to intraday offer updates and that make intraday offer updates. In the first three months of 2023, an average of 333 units per day made hourly offers, no change from the first three months of 2022. In the first three months of 2023, 518 units opted in for intraday offer updates, an increase of 39 units from the first three months of 2022. In the first three months of 2023, an average of 124 units made intraday offer updates each day, a decrease of seven units from the first three months of 2022.

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

	Fuel Type	2022 (Jan-Mar)	2023 (Jan-Mar)	Difference
Hourly Offers	Natural Gas	307	300	(7)
	Other Fuels	26	33	7
	Total	333	333	0
Opt In	Natural Gas	387	397	10
	Other Fuels	92	121	29
	Total	479	518	39
Intraday Offer Updates	Natural Gas	123	115	(8)
	Other Fuels	8	9	1
	Total	131	124	(7)
Total Units with nonzero offers		1,002	973	(29)

ICAP Must Offer Requirement

Generation capacity resources are required to offer their full ICAP MW into the day-ahead and real-time energy market, or report an outage for the difference.[37] The full installed capacity (ICAP) is the ICAP of the resources that cleared in the capacity market. This is known as the ICAP must offer requirement.

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

The current enforcement of the ICAP must offer requirement is inadequate.[38] The problem is a complex combination of generator behavior, and inadequate and inconsistent reporting tools that are not synchronized. Compliance is subject to mistakes and susceptible to manipulation.

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

For example, ambient ratings are an issue. When the weather is hotter than test conditions, the capacity of some units is reduced below the ICAP levels. While this fact may be reported by unit owners in eDART and reflected in lower offered MW in the energy market, the derates are not reported as outages in eGADS and are therefore not included as outages for purposes of defining capacity using EFORd. For planning purposes, PJM acknowledges this discrepancy, but instead of reflecting the derates in the supply offers from the units that are actually derated, PJM increases the demand for capacity to account for the loss of supply due to ambient derates.[39]

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

37 OA Schedule 1 § 1.10.1A(d).

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

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

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

Table 3-14 shows average hourly MW, for each month, that violated the ICAP must offer requirement in the first three months of 2023. On average for all hours, 921 MW did not meet the ICAP must offer requirement, but for 10 percent of the hours 1,883 MW did not meet the must offer requirement. These MW levels are larger than the reserve shortages that trigger scarcity pricing and larger than most supply contingencies that lead to synchronized reserve events.

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

Month	90th Percentile	Average	10th Percentile
Jan-23	2,218	1,257	265
Feb-23	1,252	676	295
Mar-23	1,440	808	364
2023	1,883	921	310

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

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

Emergency Maximum MW

Generation resources are offered with economic maximum MW and emergency maximum MW. The economic maximum MW is the output level the resource can achieve following economic dispatch. The emergency maximum MW is the output level the resource can achieve when emergency conditions are declared by PJM. The MW difference between the two ratings equals emergency maximum MW. The PJM market rules allow generators to include emergency maximum MW as part of ICAP offered in the capacity market.[40]

Generation resources have to meet one of four conditions to offer any MW as emergency in the energy market: environmental limits imposed by a federal, state or other governmental agency that significantly limit availability; fuel limits beyond the control of the generation owner; temporary emergency conditions that significantly limit availability; or temporary MW additions not ordinarily available.[41]

The MMU recommends that capacity resources not be allowed to offer any portion of their capacity market obligation as maximum emergency energy.[42] Capacity resources should offer their full output in the energy market and subject to economic dispatch. The result will be incentives for correct reporting of ICAP, more efficient energy market pricing, and a reduction in the need for manual overrides by PJM dispatchers during emergency conditions. Resources that do have capacity that can only be achieved with extraordinary measures could offer such capacity in the energy market but should not take on a capacity market obligation.

Table 3-15 shows average hourly maximum emergency MW, for each month. The levels of maximum emergency MW change hourly, daily and seasonally. For example, in February 2023, 10 percent of hours had maximum emergency MW greater than or equal to 2,370 MW while 10 percent of hours had maximum emergency MW less than 624 MW. The hourly average, in the first three months of 2023, was 1,282 MW offered as maximum emergency, 47.6 percent lower than in the first three months of 2022.

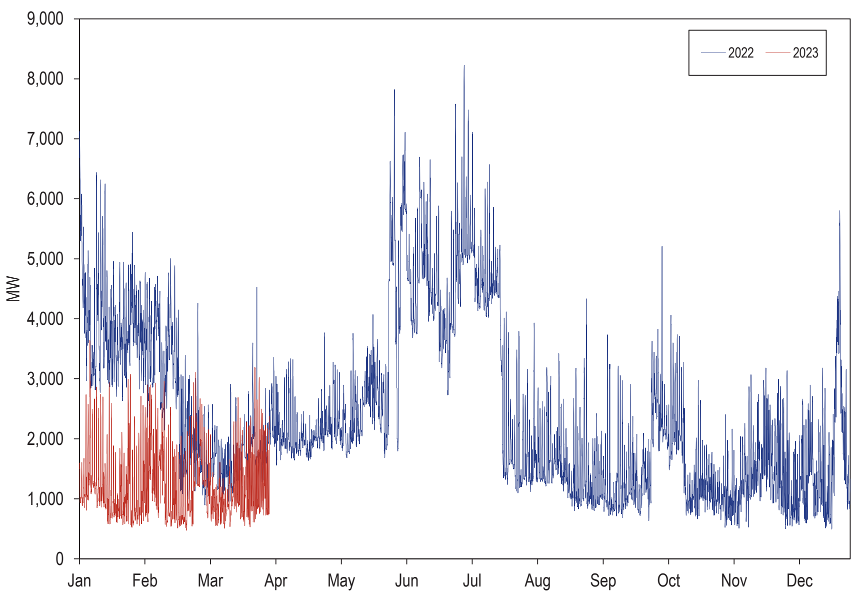
40 See 151 FERC ¶ 61,208 at P 476 (2015).
41 OA Schedule 1 § 1.10.1A(d).
42 This recommendation was accepted by PJM and filed with FERC in 2014 as part of the capacity performance updates to the RPM. See PJM Filing, Attachment A (Redlines of OA Schedule 1 § 1.10.1A(d), EL15-29-000 (December 12, 2014).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

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

Month	90th Percentile	Average	10th Percentile
Jan-23	2,338	1,244	656
Feb-23	2,370	1,350	624
Mar-23	2,132	1,260	679
2023	2,229	1,282	650

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

Figure 3-18 Maximum Emergency MW by hour: 2022 and 2023



Parameter Limited Schedules

Cost-Based Offers

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

Price-Based Offers

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

The current implementation is not consistent with the goal of having parameter limited schedules, which is to prevent the use of inflexible operating parameters to exercise market power. Instead of ensuring that parameter limits apply, PJM chooses the lower of the price-based schedule and the price-based parameter limited schedule during hot and cold weather alerts. Instead of ensuring that parameter limits apply, PJM chooses the lower of the price-based schedule and the cost-based parameter limited schedule when a resource fails the TPS test. The Commission recognized this flaw in the implementation of market power mitigation in its order to show cause, issued June 17, 2021.[43]

PJM did not attempt to address this issue in 2022 or the first three months of 2023. PJM has an opportunity to address the issue in the implementation of enhanced combined cycle modelling development. The process that PJM currently uses to determine the least cost schedule is computationally intensive in the day-ahead market on hot and cold weather alert days. Implementing

43 See 175 FERC ¶ 61,231 (2021).

the MMU's recommendations would both solve the market power mitigation issues and decrease the day-ahead market solution time.[44]

The MMU analyzed the extent of parameter mitigation in the day-ahead energy market when units are committed after failing the TPS test for transmission constraints in the first three months of 2023. The analysis includes units with technologies that are subject to parameter limits and offer both price-based and cost-based schedules.[45] Table 3-16 shows the number and percentage of day-ahead unit run hours that failed the TPS test but were committed on price schedules. Table 3-16 shows that 34.6 percent of unit hours for units that failed the day-ahead TPS test were committed on price-based schedules that were less flexible than their cost-based schedules. For effective market power mitigation there would be zero units that fail the TPS test committed with parameters less flexible than their cost-based schedules.

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

Day-ahead Commitment For Units That Failed TPS Test	Day-ahead Unit Hours	Percent Day-ahead Unit Hours
Committed on price schedule less flexible than cost	5,888	34.6%
Committed on price schedule as flexible as cost	1,844	10.8%
Total committed on price schedule without parameter limits	7,732	45.4%
Committed on cost (cost capped)	9,084	53.3%
Committed on price PLS	223	1.3%
Total committed on PLS schedules (cost or price PLS)	9,307	54.6%

The MMU analyzed the extent of parameter mitigation in the day-ahead energy market for units in zones where a cold weather alert or a hot weather alert or maximum generation emergency was declared in the first three months of 2023. PJM declared cold weather alerts on three days in the first three months of 2023.[46] The analysis includes units with technologies that are subject to parameter limits, with a CP commitment, in the zones where the cold or hot weather alerts were declared. Table 3-17 shows that 27.0 percent of unit hours during weather alerts in the day-ahead energy market were committed on price-based schedules that were less flexible than their price PLS schedules.[47] Effective market power mitigation would result in zero units committed during cold and hot weather alerts with parameters less flexible than their price PLS schedules.

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

Day-ahead Commitment During Hot And Cold Weather Alerts	Day-ahead Unit Hours	Percent Day-ahead Unit Hours
Committed on price schedule less flexible than PLS	3,675	27.0%
Committed on price schedule as flexible as PLS	705	5.2%
Total committed on price schedule without parameter limits	4,380	32.2%
Committed on cost (cost capped)	554	4.1%
Committed on price PLS	8,689	63.8%
Total committed on PLS schedules (cost or price PLS)	9,243	67.8%

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

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

If flexible parameters are not required at all times, the use of flexible parameters should be required whenever a unit fails the TPS test and whenever the system is facing emergency conditions. This would require that PJM apply the full set of approved unit specific parameters to a resource that offers any inflexible

44 See "Offer Capping Issue Charge," MMU Presentation to the Market Implementation Committee (January 11, 2023), <http://www.monitoringanalytics.com/reports/Presentations/2023/IMM_MIC_Offer_Capping_and_Combined_Cycle_Modeling_Presentation_20230111.pdf>.
45 Nuclear, wind, solar and hydro units are not subject to parameter limits.
46 *2022 State of the Market Report for PJM*, Section 3: Energy Market, at Emergency Procedures.
47 Nuclear, wind, solar and hydro units are not subject to parameter limits.

parameter under these conditions. The selection of the lowest cost offer, based on the financial parameters, would follow the application of PLS parameters.

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

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

The MMU recommends, if the preferred recommendation is not implemented, that in order to ensure effective market power mitigation, PJM always enforce parameter limited values when the TPS test is failed and during high load conditions such as cold and hot weather alerts and emergency conditions. PJM would separately mitigate the operating parameters and the financial parameters of the offers (incremental offer, startup cost, and no load cost).[48]

Parameter Limits

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

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

Unit Specific Adjustment Process

Market participants can request an adjustment to the default values of parameter limits for capacity performance resources by submitting supporting documentation which is reviewed by PJM and the MMU. The default minimum operating parameter limits or approved adjusted values are used by capacity performance resources for their parameter limited schedules.

PJM has the authority to approve adjusted parameters with input from the MMU. PJM has inappropriately applied different review standards to coal units than to CTs and CCs despite the objections of the MMU. PJM has approved parameter limits for boiler based steam units based on historical performance and existing equipment while holding CTs and CCs to higher standards based on OEM documentation and a best practices equipment configuration.

The PJM process for the review of unit specific parameter limit adjustments is generally described in Manual 11: Energy and Ancillary Services Market Operations. The standards used by PJM to review the requests are currently not described in the tariff or PJM manuals. The MMU recommends that PJM clearly define the business rules that apply to the unit specific parameter adjustment process, including PJM's implementation of the tariff rules in the PJM manuals to ensure market sellers know the requirements for their resources.

Only certain technology types are subject to limits on operating parameters in their parameter limited schedules.[49] Solar units, wind units, run of river hydro units, and nuclear units are currently not subject to parameter limits. The MMU analyzed, for the units that are subject to parameter limits, the proportion of units that use the default limits published by PJM and the

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

49 For the default parameter limits by technology type, see PJM. "Unit-Specific Minimum Operating Parameters for Capacity Performance and Base Capacity Resources," which can be accessed at <https://www.pjm.com/~/media/committees-groups/committees/elc/postings/20150612-june-2015-capacity-performance-parameter-limitations-informational-posting.ashx>.

proportion of units that have been provided unit specific adjustments for some of the parameters. Table 3-18 shows, for the delivery year beginning June 1, 2022, the number of units that submitted and had approved unit specific parameter limit adjustments, and the number of units that used the default parameter limits published by PJM.

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

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

Real-Time Values

The Commission rejected PJM's proposed revisions to add RTV rules to the tariff in an order issued on May 28, 2021. In its order, the Commission recognized that RTVs can be used to exercise market power by withholding generation and avoiding market power mitigation.[50]

The real-time values submittal process was never defined in the PJM Operating Agreement. The process was defined only in PJM Manual 11. While there are a number of options for providing real-time unit status to PJM operators, PJM created a mechanism for the submission of such values called real-time values (RTVs). Unlike parameter exceptions, the use of real-time values made a unit ineligible for make whole payments, unless the market seller could justify such operation based on an actual constraint.[51] In the case of the notification time parameter, start time parameter, minimum run time and minimum down time parameters, a longer real-time value decreases the likelihood of the unit being committed, making the RTV a mechanism for exercising market power through withholding and for failing to meet the obligations of capacity resources.

PJM's proposed RTV mechanism was rejected by the Commission because it would weaken the existing market power mitigation rules including parameter limited schedules.[52]

Beginning August 1, 2021, PJM provides guidance to market sellers that it will no longer accept real-time value submissions for economic reasons, such as due to choosing not to staff a unit. In its order to show cause issued on June 17, 2021, the Commission stated its concern that "the PJM Tariff appears to be unjust and unreasonable because it fails to contain provisions governing what happens if a seller is unable to meet its unit-specific parameters in real time".[53] In its response to the Commission's order, PJM proposed tariff updates to allow generators to submit temporary exceptions during the operating day.[54] These proposed rules require market sellers to justify that the request is based on a physical and actual constraint by submitting supporting documentation within three business days, consistent with the existing temporary parameter exception process. Without a response from FERC on its proposed rules, in the first three months of 2023, PJM proposed revisions to Manual 11 memorializing its current practice, based on the proposed rules that have not been approved by FERC.

The revisions include no consequences for market sellers who do not adhere to the proposed rules. Currently, a resource that is staffed or has remote start capability and offers according to its physical capability, and a resource that makes the economic choice not to staff or invest in remote start and economically or physically withholds to decrease the likelihood of commitment, are compensated identically in the capacity market. If a market seller makes an economic decision to not staff the unit or to not have remote start capability, and uses temporary parameter exceptions or RTVs to communicate the longer time to start to PJM, the unit's actual parameters are not recognized as inconsistent with its obligations as a capacity resource, not

50 175 FERC ¶ 61,171 (2021).
51 See OA Schedule 1 § 3.2.3(e).
52 175 FERC ¶ 61,171 at P 36 (2021).
53 175 FERC ¶ 61,231 at P 17 (2021).
54 PJM. "Answer of PJM Interconnection LLC," Docket No. EL21-78 (September 15, 2021)("September 15th Response").

reflected in forced outages, and not reflected in eligibility for uplift payments. The market seller is able to withhold the unit in the energy market with no defined consequence, while other similarly situated units incur the costs associated with meeting their obligations. Such withholding is an exercise of market power. If market sellers instead represent that they are able to meet the time to start parameters, but the unit is not staffed or the unit is not equipped with remote start capability to meet its unit specific limits, there is no defined consequence for misrepresenting the unit's capability. In its September 15th Response, PJM proposes no explicit defined penalties for such behavior.

Units that override their turn down ratio (economic maximum divided by economic minimum) either use Real-Time Values or PJM's fixed gen flag, which functions identically to a real-time value.[55] These resources operate on their parameter limited schedules but override their output limit parameters with no consequence. The only difference between a Real-Time Value to override the turn down ratio parameter and the fixed gen flag is that the fixed gen resources receive uplift payments. These resources receive inefficient levels of uplift payments when they have market power. The September 15th Response does not address unstaffed units that refuse to meet their notification time or units that refuse to perform to their turn down ratio parameter by using fixed gen.

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

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

The better option, consistent with the no excuses approach of the capacity performance paradigm and consistent with long term incentives for flexibility, is to not pay any capacity resources an appropriate portion of the daily capacity value of the resource for days when it is not fully available consistent with its parameter limited schedule. If flexibility is valued as a generator attribute, the market design should not provide incentives to be inflexible. An effective market design should reward flexible operation, and ensure that Capacity Performance resources are paid for their capacity only when it meets their required level of flexibility. Without clearly defined consequences, market sellers will continue to submit inflexible parameters. The MMU recommends that resources not be paid the daily capacity payment when unable to operate to their unit specific parameter limits.[56]

Generator Flexibility Incentives under Capacity Performance

In its June 9, 2015, order on capacity performance, the Commission determined that capacity performance resources should be able to reflect actual constraints based on not just the resource physical constraints, but also other constraints, such as contractual limits that are not based on the physical characteristics of the generator.[57] The Commission directed that capacity performance resources with parameters based on nonphysical constraints should receive uplift payments.[58] The Commission directed PJM to submit tariff language to establish a process through which capacity performance resources that operate outside the defined unit specific parameter limits can justify such operation and therefore remain eligible for make whole payments.[59]

A primary goal of the capacity performance market design is to assign performance risk to generation owners and to ensure that capacity prices reflect underlying supply and demand conditions, including the cost of taking on performance risk. The June 9th Order's determination on parameters is not consistent with that goal. By permitting generation owners to establish unit parameters based on nonphysical limits, the June 9th Order weakened

56 *See* Monitoring Analytics LLC, "Real-Time Values," presented at the Markets Implementation Committee Special Session (October 7, 2020) at 12, *which can be accessed at* <https://www.pjm.com/-/media/committees-groups/committees/mic/2020/20201007/20201007-item-06b-real-time-values-imm.ashx>.
57 151 FERC ¶ 61,208 at P 437 (2015) (June 9th Order).
58 *Id* at P 439.
59 *Id* at P 440.

the incentives for units to be flexible and weakened the assignment of performance risk to generation owners. Contractual limits, unlike generating unit operational limits, are a function of the interests and incentives of the parties to the contracts. If a generation owner expects to be compensated through uplift payments for running for 24 hours regardless of whether the energy is economic or needed, that generation owner has no incentive to pay more to purchase the flexible gas service that would permit the unit to be flexible in response to dispatch.

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

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

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

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

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

Parameter Impacts of Gas Pipeline Conditions

During extreme cold weather conditions, and more recently, also during hot weather conditions, a number of gas fired generators request temporary exceptions to parameter limits for their parameter limited schedules due to restrictions imposed by natural gas pipelines. The parameters affected include notification time, minimum run time (MRT) and turn down ratio (TDR, the ratio of economic maximum MW to economic minimum MW). When pipelines issue critical notices and enforce ratable take requirements, generators may, depending on the nature of the transportation service purchased, be forced to nominate an equal amount of gas for each hour in a 24 hour period, with penalties for deviating from the nominated quantity. This leads to requests for 24 hour minimum run times and turn down ratios close to 1.0, to avoid deviations from the hourly nominated quantity. Table 3-19 shows the number of units, and the installed capacity MW that submitted parameter exception requests for a 24 hour minimum run time due to gas pipeline restrictions. In the first three months of 2023, there were 72 units in PJM with a total installed capacity of 9,374 MW that requested a 24 hour minimum run time on their parameter limited schedules based on pipeline restrictions.

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

Year (Jan - Mar)	Number of Units With 24 Hour Minimum Run Time Exceptions	Installed Capacity (MW) With 24 Hour Minimun Run Time Exceptions
2018	23	3,314
2019	37	5,616
2020	8	3,448
2021	53	7,145
2022	60	7,212
2023	72	9,374

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

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

The MMU recommends that PJM not approve temporary exceptions that are based on pipeline tariff terms that are not enforced at the time, or are based on inferior transportation service procured by the generator.

Virtual Offers and Bids

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

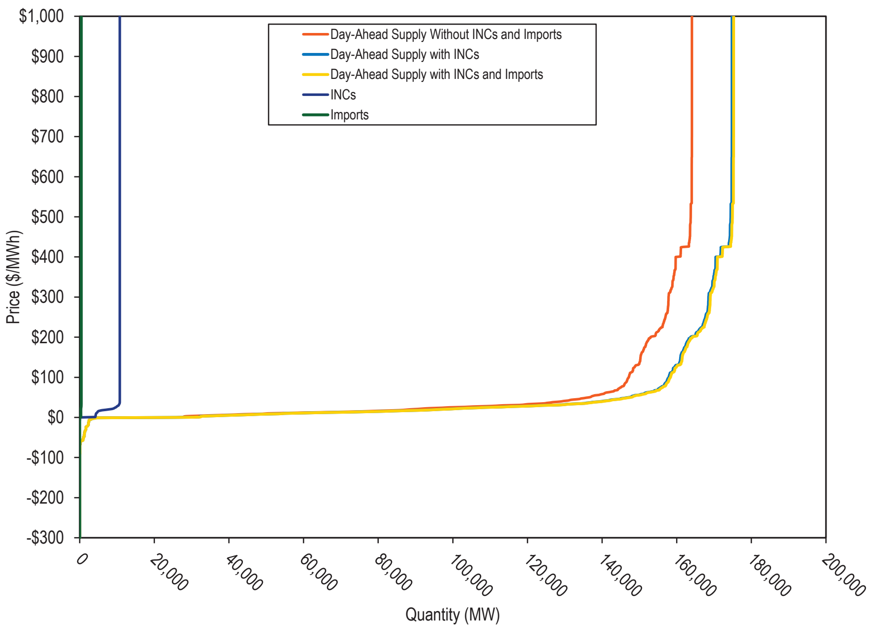
Any market participant in the PJM Day-Ahead Energy Market can use increment offers, decrement bids, up to congestion transactions, import transactions and export transactions as financial instruments that do not require physical generation or load. Because virtual positions do not require physical generation or load, participants must buy or sell out of their virtual positions at real-time energy market prices. On February 20, 2018, FERC issued an order limiting the eligible bidding points for up to congestion transactions to hubs, interfaces and residual aggregate metered load nodes, and limiting the eligible bidding points for INCs and DECs to the same nodes plus active generation and load nodes.[60] Up to congestion transactions may be submitted between any two buses on a list of 47 buses eligible for up to congestion

60 162 FERC ¶ 61,139 (2018).

transaction bidding.[61] Import and export transactions may be submitted at any interface pricing point, where an import is equivalent to a virtual offer that is injected into PJM and an export is equivalent to a virtual bid that is withdrawn from PJM.

Figure 3-19 shows the PJM day-ahead daily aggregate supply curve of increment offers, the system aggregate supply curve of imports, the system aggregate supply curve without increment offers and imports, the system aggregate supply curve with increment offers, and the system aggregate supply curve with increment offers and imports for an example day in the first three months of 2023.

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



61 Prior to November 1, 2012, market participants were required to specify an interface pricing point as the source for imports, an interface pricing point as the sink for exports or an interface pricing point as both the source and sink for transactions wheeling through PJM. For the list of eligible sources and sinks for up to congestion transactions, see www.pjm.com "*OASIS-Source-Sink-Link.xls*," <http://www.pjm.com/~/media/etools/oasis/references/oasis-source-sink-link.ashx>.

Table 3-20 shows the hourly average number of cleared and submitted increment offers and decrement bids by month in 2022 and the first three months of 2023. The hourly average submitted increment offer MW increased by 5.6 percent and cleared increment MW increased by 25.2 percent in the first three months of 2023 compared to the first three months of 2022. The hourly average submitted decrement bid MW decreased by 23.3 percent and cleared decrement MW decreased by 25.1 percent in the first three months of 2023 compared to the first three months of 2022.

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

		Increment Offers				Decrement Bids			
Year		Average Cleared MW	Average Submitted MW	Average Cleared Volume	Average Submitted Volume	Average Cleared MW	Average Submitted MW	Average Cleared Volume	Average Submitted Volume
2022	Jan	2,898	7,135	308	1,069	6,513	14,228	375	1,559
2022	Feb	3,743	8,639	359	1,216	6,078	13,359	348	1,370
2022	Mar	4,072	9,403	337	1,143	5,579	12,511	256	1,074
2022	Apr	3,909	8,696	342	1,069	3,833	11,008	196	1,026
2022	May	3,588	8,381	319	1,029	4,960	12,441	247	1,072
2022	Jun	3,467	7,708	249	909	4,719	11,482	234	1,032
2022	Jul	3,060	7,249	266	1,068	4,451	10,703	192	976
2022	Aug	3,112	6,696	259	973	4,889	11,092	241	997
2022	Sep	3,352	7,280	257	1,109	6,157	11,806	287	1,003
2022	Oct	3,603	7,979	304	969	4,813	11,978	320	1,280
2022	Nov	4,586	9,985	373	1,268	4,504	12,304	307	1,229
2022	Dec	3,587	8,012	322	1,090	4,637	12,786	310	1,386
2022	Annual	3,578	8,089	308	1,075	5,089	12,137	276	1,167
2023	Jan	3,870	7,847	319	949	4,421	9,941	307	1,076
2023	Feb	4,994	9,786	426	1,190	4,583	9,732	258	933
2023	Mar	4,578	9,008	415	1,068	4,613	11,030	316	1,113
2023	Jan-Mar	4,463	8,850	385	1,065	4,537	10,251	295	1,045

Table 3-21 shows the average hourly number of up to congestion transactions and the average hourly MW by month in 2022 and the first three months of 2023. The volume of bid and cleared up to congestion transactions increased dramatically during this time. The hourly average submitted up to congestion bid MW increased by 186.1 percent and cleared up to congestion bid MW increased by 135.2 percent in the first three months of 2023 compared to the first three months of 2022.

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

		Up to Congestion			
Year		Average Cleared MW	Average Submitted MW	Average Cleared Volume	Average Submitted Volume
2022	Jan	8,268	28,791	478	1,322
2022	Feb	11,908	31,383	632	1,452
2022	Mar	10,921	34,887	521	1,366
2022	Apr	9,030	37,400	440	1,342
2022	May	8,616	34,312	438	1,277
2022	Jun	10,213	31,573	520	1,305
2022	Jul	11,009	35,453	624	1,669
2022	Aug	15,007	48,449	756	2,143
2022	Sep	13,259	48,064	853	2,245
2022	Oct	14,738	53,955	739	2,237
2022	Nov	21,784	74,103	889	2,633
2022	Dec	24,019	82,190	1,000	2,797
2022	Annual	13,239	45,134	658	1,818
2023	Jan	23,708	69,113	952	2,522
2023	Feb	24,242	87,218	1,003	3,156
2023	Mar	24,834	115,463	961	3,942
2023	Jan-Mar	24,262	90,699	971	3,208

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

		Imports				Exports			
Year	Month	Average Cleared MW	Average Submitted MW	Average Cleared Volume	Average Submitted Volume	Average Cleared MW	Average Submitted MW	Average Cleared Volume	Average Submitted Volume
2022	Jan	295	322	4	5	4,349	4,360	35	36
2022	Feb	271	298	4	4	4,639	4,647	37	37
2022	Mar	169	196	3	3	3,822	3,842	27	27
2022	Apr	247	269	4	4	2,085	2,110	19	20
2022	May	428	441	5	5	2,521	2,566	21	21
2022	Jun	310	320	3	3	3,084	3,118	31	31
2022	Jul	268	283	3	3	3,217	3,265	31	31
2022	Aug	308	316	3	3	4,010	4,046	32	32
2022	Sep	356	396	2	3	3,830	3,870	29	30
2022	Oct	340	356	4	4	2,786	2,813	19	19
2022	Nov	419	455	4	5	2,819	2,813	24	24
2022	Dec	471	508	4	5	3,840	3,926	30	31
2022	Annual	325	349	4	4	3,412	3,443	28	28
2023	Jan	740	843	7	8	3,879	3,944	28	28
2023	Feb	646	695	6	6	4,064	4,086	29	29
2023	Mar	371	402	3	4	3,739	3,779	28	29
2023	Jan-Mar	584	645	5	6	3,888	3,932	28	29

Table 3-22 shows the average hourly number of day-ahead import and export transactions and the average hourly MW from January 2022 through March 2023. In the first three months of 2023, the average hourly submitted import transaction MW increased by 138.3 percent and the average hourly cleared import transaction MW increased by 139.2 percent compared to the first three months of 2022. In the first three months of 2023, the average hourly submitted export transaction MW decreased by 7.9 percent and the average hourly cleared export transaction MW decreased by 8.7 percent compared to the first three months of 2022.

Table 3-23 shows the frequency with which generation offers, import or export transactions, up to congestion transactions, decrement bids, increment offers and price-sensitive demand were marginal in January 2022 through March 2023.[62]

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

	2022						2023					
	Generation	Dispatchable Transaction	Up to Congestion Transaction	Decrement Bid	Increment Offer	Price Sensitive Demand	Generation	Dispatchable Transaction	Up to Congestion Transaction	Decrement Bid	Increment Offer	Price Sensitive Demand
Jan	20.3%	0.1%	34.5%	27.6%	17.4%	0.0%	11.3%	0.8%	57.0%	18.4%	12.5%	0.0%
Feb	14.9%	0.1%	39.9%	25.5%	19.6%	0.0%	12.4%	0.1%	57.2%	15.2%	14.8%	0.0%
Mar	16.4%	0.2%	38.5%	20.4%	24.6%	0.0%	12.6%	0.1%	57.6%	16.9%	12.7%	0.0%
Apr	20.8%	0.3%	33.4%	18.5%	27.0%	0.0%						
May	17.4%	0.4%	38.8%	22.5%	20.8%	0.0%						
Jun	16.8%	0.2%	43.8%	23.8%	15.2%	0.0%						
Jul	15.5%	0.3%	47.7%	21.4%	14.9%	0.0%						
Aug	15.8%	0.2%	49.2%	19.3%	15.3%	0.0%						
Sep	22.2%	0.5%	45.5%	17.7%	14.0%	0.0%						
Oct	18.3%	0.3%	43.3%	19.4%	18.7%	0.0%						
Nov	15.1%	0.3%	51.4%	18.7%	14.5%	0.0%						
Dec	13.3%	0.5%	58.9%	17.7%	9.6%	0.0%						
Annual	17.1%	0.3%	44.1%	21.1%	17.4%	0.0%	12.1%	0.3%	57.3%	16.9%	13.3%	0.0%

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

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

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

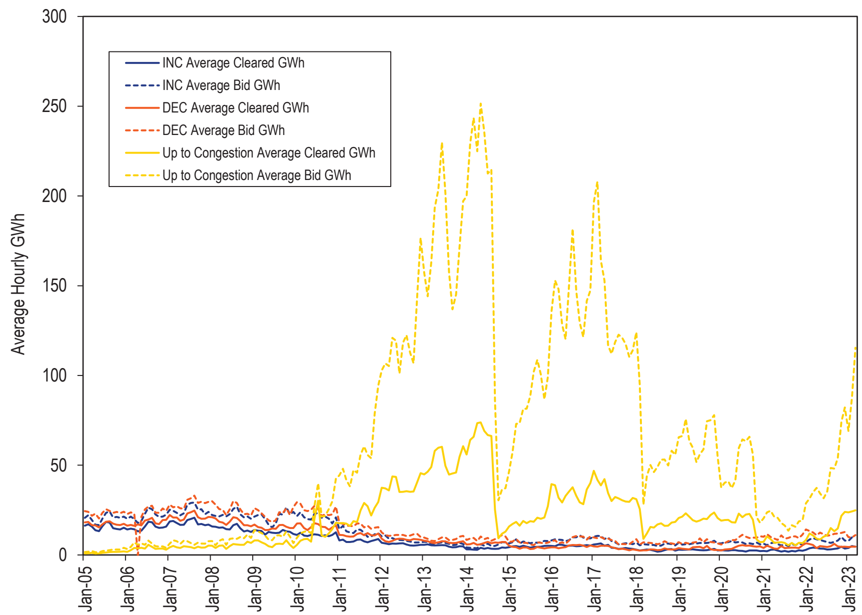
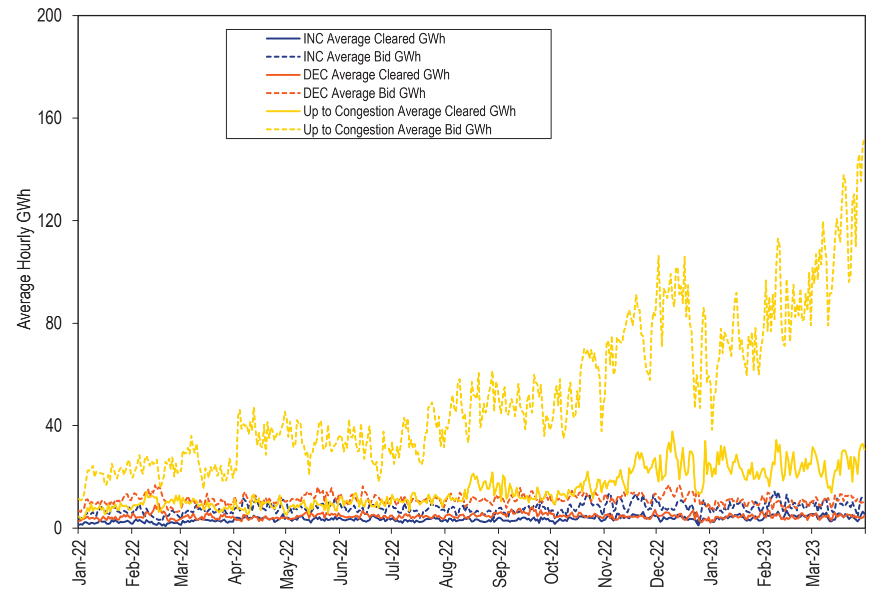


Figure 3-21 shows the daily volume of bid and cleared INC, DEC and up to congestion bids from January 2022 through March 2023. During this period, the volume of bid and cleared up to congestion transactions increased significantly.

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



In order to evaluate the ownership of virtual bids, the MMU categorizes all participants making virtual bids in PJM as either physical or financial. Physical entities include utilities and customers that primarily take physical positions in PJM markets. Financial entities include banks and hedge funds that primarily take financial positions in PJM markets. International market participants that primarily take financial positions in PJM markets are generally considered to be financial entities even if they are utilities in their own countries. Financial entities' share of submitted and cleared MWh of INCs and DECs in the first three months of 2023 was slightly lower than in the first three months of 2022, but still made up the majority of all INCs and DECs.

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

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

	2022 (Jan-Mar)				2023 (Jan-Mar)			
Category	Total Virtual Bid MWh	Percent	Total Virtual Cleared MWh	Percent	Total Virtual Bid MWh	Percent	Total Virtual Cleared MWh	Percent
Financial	43,152,621	91.9%	17,964,116	86.5%	37,411,499	90.7%	16,495,389	84.9%
Physical	3,805,969	8.1%	2,807,433	13.5%	3,827,776	9.3%	2,937,324	15.1%
Total	46,958,589	100.0%	20,771,549	100.0%	41,239,275	100.0%	19,432,713	100.0%

Table 3-25 shows, in the first three months of 2022 and 2023, the total up to congestion bid and cleared MWh by type of parent organization. Up to congestion bids submitted by financial entities more than tripled in the first three months of 2023 compared the first three months of 2022, from 64 million MWh to 195 million MWh, while up to congestion bids submitted by physical entities decreased. Financial entities submitted 99.6 percent of all up to congestion bids, up from 93.9 percent, and 99.3 percent of all cleared up to congestion bids, up from 92.1 percent. In the first three months of 2023, almost all up to congestion trading activity by financial participants.

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

	2022 (Jan-Mar)				2023 (Jan-Mar)			
Category	Total Up to Congestion Bid MWh	Percent	Total Up to Congestion Cleared MWh	Percent	Total Up to Congestion Bid MWh	Percent	Total Up to Congestion Cleared MWh	Percent
Financial	64,228,520	93.9%	20,500,047	92.1%	195,117,944	99.6%	51,992,392	99.3%
Physical	4,202,713	6.1%	1,768,436	7.9%	697,956	0.4%	386,678	0.7%
Total	68,431,234	100.0%	22,268,483	100.0%	195,815,900	100.0%	52,379,070	100.0%

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

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

		2022 (Jan-Mar)		2023 (Jan-Mar)	
	Category	Total Import and Export MWh	Percent	Total Import and Export MWh	Percent
Day-Ahead	Financial	3,988,381	41.2%	2,906,170	30.2%
	Physical	5,686,239	58.8%	6,724,989	69.8%
	Total	9,674,620	100.0%	9,631,159	100.0%
Real-Time	Financial	5,613,858	30.8%	4,324,362	25.2%
	Physical	12,605,884	69.2%	12,803,123	74.8%
	Total	18,219,742	100.0%	17,127,485	100.0%

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

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

2022 (Jan-Mar)					2023 (Jan-Mar)				
Aggregate/Bus Name	Aggregate/Bus Type	INC MWh	DEC MWh	Total MWh	Aggregate/Bus Name	Aggregate/Bus Type	INC MWh	DEC MWh	Total MWh
MISO	INTERFACE	27,809	1,836,331	1,864,140	MISO	INTERFACE	98,270	1,602,650	1,700,919
WESTERN HUB	HUB	310,693	1,494,856	1,805,548	WESTERN HUB	HUB	485,144	792,624	1,277,768
NYIS	INTERFACE	152,772	857,154	1,009,926	SOUTH	INTERFACE	1,117,238	52,224	1,169,462
LINDENVFT	INTERFACE	10,392	640,990	651,382	N ILLINOIS HUB	HUB	375,542	230,112	605,654
SOUTH	INTERFACE	506,153	141,786	647,940	DOM_RESID_AGG	RESIDUAL METERED EDC	50,598	544,371	594,969
DOM_RESID_AGG	RESIDUAL METERED EDC	40,991	527,580	568,570	LINDENVFT	INTERFACE	14,773	552,299	567,072
N ILLINOIS HUB	HUB	237,124	191,050	428,174	NYIS	INTERFACE	163,755	362,117	525,872
NEW JERSEY HUB	HUB	174,334	250,392	424,726	AEP-DAYTON HUB	HUB	154,658	279,640	434,299
EASTERN HUB	HUB	128,097	250,636	378,733	BGE_RESID_AGG	RESIDUAL METERED EDC	118,990	243,376	362,366
DOMINION HUB	HUB	123,624	239,242	362,866	EASTERN HUB	HUB	62,995	222,858	285,853
Top ten total		1,711,988	6,430,017	8,142,005			2,641,962	4,882,272	7,524,233
PJM total		7,696,896	13,074,653	20,771,549			9,636,422	9,796,291	19,432,713
Top ten total as percent of PJM total		22.2%	49.2%	39.2%			27.4%	49.8%	38.7%

Table 3-28 shows up to congestion transactions for the top 10 source and sink pairs and associated source, sink and overall profits on each path in the first three months of 2022 and 2023. Total profits for up to congestion transactions in the first three months of 2023 were $23.5 million, a decrease of 39.3 percent compared to profits of $38.7 million in the first three months of 2022.[63] The UTCs from DOMINION HUB to DOM RESID AGG constituted 64 percent of all UTC profits in the first three months of 2023. Congestion in the Dominion Zone in the first three months of 2023 resulted from the continuing increase in data center load in Northern Virginia. The increase in UTCs on this path alone, which made up more than 20 percent of all cleared UTC MW, was a major contributor to the overall increase in UTC volumes in 2022 and the first three months of 2023.

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

Table 3-28 Cleared up to congestion bids by top 10 source and sink pairs (MWh): January through March, 2022 and 2023[64]

2022 (Jan-Mar)							
Top 10 Paths by Cleared MWh							
Source	Source Type	Sink	Sink Type	Cleared MW	Source Revenue	Sink Revenue	UTC Profit
WESTERN HUB	HUB	DOMINION HUB	HUB	684,803	$3,241,288	($1,825,889)	$1,319,399
CHICAGO GEN HUB	HUB	EKPC_RESID_AGG	AGGREGATE	533,021	$712,129	($291,146)	$352,396
SOUTH	INTERFACE	AEPAPCO_RESID_AGG	AGGREGATE	517,307	$2,495,600	($114,965)	$2,214,090
EKPC_RESID_AGG	AGGREGATE	AEPAPCO_RESID_AGG	AGGREGATE	511,365	$2,375,236	($1,747,225)	$491,052
AEPIM_RESID_AGG	AGGREGATE	AEPOHIO_RESID_AGG	AGGREGATE	499,766	$1,763,771	($1,163,691)	$530,841
MISO	INTERFACE	DEOK_RESID_AGG	AGGREGATE	401,747	$1,036,971	($764,233)	$237,395
ATSI GEN HUB	HUB	OVEC_RESID_AGG	AGGREGATE	378,579	$468,867	($148,542)	$272,608
AEPIM_RESID_AGG	AGGREGATE	AEP-DAYTON HUB	HUB	331,564	$709,150	($521,427)	$138,399
MISO	INTERFACE	EKPC_RESID_AGG	AGGREGATE	322,636	$597,567	($533,976)	$36,983
CHICAGO GEN HUB	HUB	DEOK_RESID_AGG	AGGREGATE	318,993	$540,745	($283,230)	$211,109
Top ten total				4,499,778	$13,941,323	($7,394,323)	$5,804,273
PJM total				60,161,965	$49,602,398	($7,000,368)	$38,655,527
Top ten total as percent of PJM total				7.5%	28.1%	105.6%	15.0%
2023 (Jan-Mar)							
Top 10 Paths by Cleared MWh							
Source	Source Type	Sink	Sink Type	Cleared MWh	Source Revenue	Sink Revenue	UTC Profit
DOMINION HUB	HUB	DOM_RESID_AGG	AGGREGATE	11,750,746	$12,274,590	$3,988,642	$15,105,596
AEP GEN HUB	HUB	EKPC_RESID_AGG	AGGREGATE	1,375,868	$1,825,726	($1,451,008)	$274,254
CHICAGO GEN HUB	HUB	AEPIM_RESID_AGG	AGGREGATE	1,066,901	$758,360	($548,051)	$126,338
CHICAGO GEN HUB	HUB	CHICAGO HUB	HUB	982,617	($105,891)	$251,187	$50,380
WESTERN HUB	HUB	DOM_RESID_AGG	AGGREGATE	760,024	$2,018,625	($741,263)	$1,195,521
COMED_RESID_AGG	AGGREGATE	AEPIM_RESID_AGG	AGGREGATE	756,250	$984,494	($999,773)	($68,942)
APS_RESID_AGG	AGGREGATE	DOM_RESID_AGG	AGGREGATE	728,217	$672,965	$466,929	$1,067,862
BGE_RESID_AGG	AGGREGATE	DOM_RESID_AGG	AGGREGATE	633,015	$2,519,392	($334,962)	$2,112,183
CHICAGO GEN HUB	HUB	MISO	INTERFACE	559,407	$668,437	($706,075)	($73,907)
MISO	INTERFACE	AEPIM_RESID_AGG	AGGREGATE	497,270	$1,306,060	($1,032,768)	$238,182
Top ten total				19,110,315	$22,922,759	($1,107,141)	$20,027,467
PJM total				52,380,802	$76,839,358	($48,572,834)	$23,527,155
Top ten total as percent of PJM total				36.5%	29.8%	2.3%	85.1%

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

Table 3-29 shows the average daily number of source-sink pairs that were offered and cleared each month from January 2022 through March 2023. The average number of submitted source-sink pairs per day increased from 1,480 source-sink pairs submitted in 2022 to 1,521 in the first three months of 2023. The average number of cleared source-sink pairs per day increased from 1,282 in 2022 to 1,294 per day in the first three months of 2023. The increase in the number of traded paths was smaller than the increase in the volume of MWh bid and cleared, meaning that was increased concentration of trades by path.

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

		Daily Number of Source-Sink Pairs			
Year	Month	Average Offered	Max Offered	Average Cleared	Max Cleared
2022	Jan	1,398	1,555	1,228	1,405
2022	Feb	1,501	1,633	1,296	1,488
2022	Mar	1,392	1,609	1,178	1,449
2022	Apr	1,415	1,513	1,174	1,274
2022	May	1,417	1,525	1,181	1,291
2022	Jun	1,488	1,644	1,253	1,458
2022	Jul	1,551	1,703	1,305	1,478
2022	Aug	1,689	1,782	1,394	1,521
2022	Sep	1,686	1,855	1,436	1,646
2022	Oct	1,625	1,884	1,336	1,638
2022	Nov	1,552	1,754	1,301	1,497
2022	Dec	1,549	1,822	1,302	1,619
2022	Annual	1,522	1,690	1,282	1,480
2023	Jan	1,558	1,723	1,239	1,480
2023	Feb	1,705	1,812	1,326	1,522
2023	Mar	1,803	1,922	1,318	1,561
2023	Jan-Mar	1,689	1,819	1,294	1,521

Table 3-30 and Figure 3-22 show total cleared up to congestion transactions and the share of the top 10 up to congestion paths by transaction type (import, export, or internal) in the first three months of 2022 and 2023. Total cleared up to congestion transactions increased by 135 percent from 22.3 million MWh in the first three months of 2022 to 52.4 million MWh in the first three months of 2023. Internal up to congestion transactions in the first three months of 2023 were 85.2 percent of all up to congestion transactions, an increase from 73.4 percent in the first three months of 2022.

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

	2022 (Jan-Mar)				
	Cleared Up to Congestion Bids				
	Import	Export	Wheel	Internal	Total
Top ten total (MW)	2,013,713	1,582,145	447,771	4,099,001	8,142,630
PJM total (MW)	2,667,575	2,770,505	477,561	16,352,842	22,268,483
Top ten total as percent of PJM total	75.5%	57.1%	93.8%	25.1%	36.6%
PJM total as percent of all up to congestion transactions	12.0%	12.4%	2.1%	73.4%	100.0%
	2023 (Jan-Mar)				
	Cleared Up to Congestion Bids				
	Import	Export	Wheel	Internal	Total
Top ten total (MW)	1,882,688	2,325,366	721,616	19,003,992	23,933,662
PJM total (MW)	2,851,223	4,125,081	798,507	44,605,991	52,380,802
Top ten total as percent of PJM total	66.0%	56.4%	90.4%	42.6%	45.7%
PJM total as percent of all up to congestion transactions	5.4%	7.9%	1.5%	85.2%	100.0%

Figure 3-22 shows the total volume of import, export, wheel, and internal up to congestion transactions by month from January 2005 through March 2023. An initial increase and continued increase in internal up to congestion transactions by month followed the November 1, 2012, rule change permitting such transactions, until September 8, 2014. The reduction in up to congestion transactions (UTC) that followed a FERC order setting September 8, 2014, as the effective date for any uplift charges subsequently assigned to UTCs, was reversed.[65] There was an increase in up to congestion volume as a result of the expiration of the 15 month refund period for the proceeding related to uplift charges for UTC transactions. In 2018, total UTC activity and the percent of marginal up to congestion transactions again decreased significantly as the result of a FERC order issued on February 20, 2018, and implemented on February 22, 2018.[66] The order limited UTC trading to hubs, residual metered load, and interfaces. UTC activity increased following that reduction.

UTC activity decreased again beginning November 1, 2020, after a FERC order requiring UTCs to pay day-ahead and balancing operating reserve charges equivalent to a DEC at the UTC sink point became effective on that date.[67] In 2022 and the first three months of 2023, the volume of cleared UTCs increased significantly, primarily internal transactions.

65 See 162 FERC ¶ 61,139 (2018).
66 *Id.*
67 See 172 FERC ¶ 61,046 (2020).

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

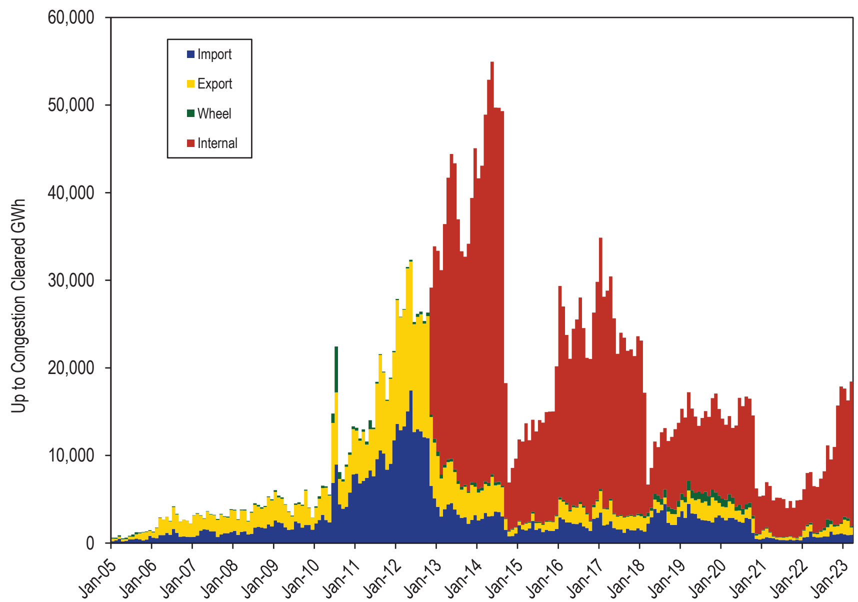
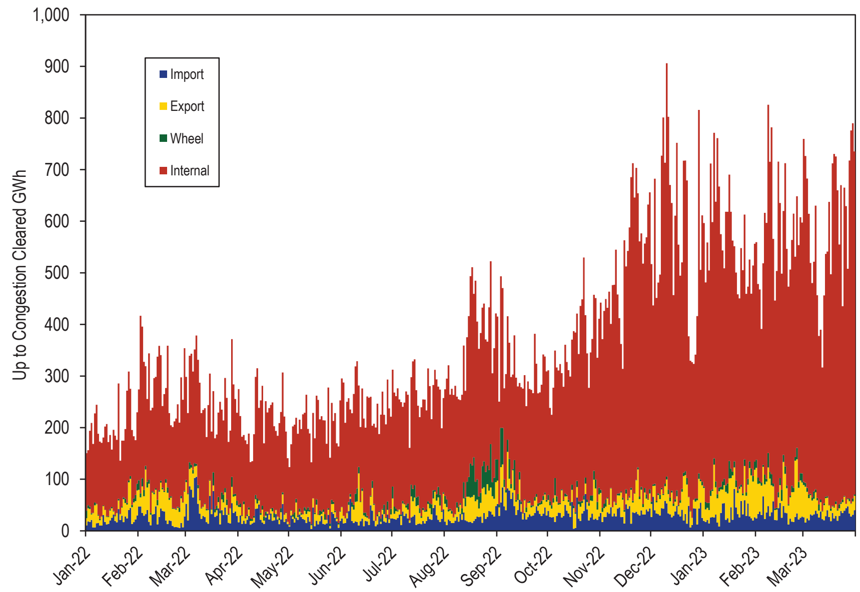


Figure 3-23 shows the daily cleared up to congestion GWh by transaction type from January 1, 2022, through March 31, 2023. In the first three months of 2023, the total cleared GWh of import and export transactions remained relatively unchanged, while internal up to congestion transactions increased significantly compared to 2022.

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



One of the goals of the February 2018 FERC order accepting PJM's proposal limiting UTC bidding to hubs, interfaces and residual aggregate metered load nodes, and limiting INC and DEC bidding to the same nodes plus active generation nodes, was to limit the opportunities for traders to profit from opportunities for false arbitrage in which price spreads between the day-ahead and real-time energy markets result from differences in the models used to operate each market that cannot be corrected through virtual bidding.[68]

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

A key assumption underlying the February 2018 order is that the limited set of nodes available for virtual trading is sufficiently protected from false arbitrage trades because price spreads resulting from modeling differences between the day-ahead and real-time markets are mitigated by the averaging of prices over a large number of buses at aggregate nodes.[69] This assumption is not correct, given the large share of INC, DEC, and UTC profits still attributable to modeling or operational differences between day-ahead and real-time since the February 2018 order.

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

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

69 162 FERC ¶ 61,139 at PP 35–36 (2018) ("We accept PJM's proposal to limit eligible bidding points for UTCs to hubs, residual metered load, and interfaces. First, we agree with the IMM's statement that PJM's proposal to limit the UTC bid locations to interfaces, zones, and hubs will minimize false arbitrage opportunities for UTCs currently being pursued through penny bids, as the effect of modeling differences between the day-ahead and real-time markets are minimized at these aggregates.").

MLSA Market Manipulation Cases

In 2009, PJM proposed rules for calculating the marginal loss surplus allocation (MLSA) that permitted allocations of marginal losses to transactions, including up to congestion transactions, which exceeded the cost of the transmission service required to support such transactions.[70] The MLSA rules were approved on September 17, 2009.[71] The order denying rehearing issued April 15, 2010, providing assurance that the MLSA rules were final.[72] On May 15, 2010 through September 17, some virtual traders engaged in economically meaningless wash trades in order to improperly obtain a share of the MLSA. Because the up to congestion trades offset or nearly offset, such traders received MLSA exceeding the cost of transmission purchased to support the transaction.

On January 6, 2011, the MMU submitted a referral of multiple entities to the FERC Office of Enforcement pursuant to OATT Section IV.I.1 of Attachment M. The referral (made public by Powhatan) detailed the manipulative scheme and recommended investigation.[73] FERC issued a series of show cause orders based on the referral and the Office of Enforcement's investigation. The show cause order resulted in assessments of penalties on virtual traders including Powhatan Energy Fund, LLC, HEEP Fund, Inc., CU Fund, Inc., and Houlian Chen (IN15-3); Coaltrain Energy, L.P., Peter Jones, Shawn Sheehan, Robert Jones, Jeff Miller, and Jack Wells (IN16-4); and City Power Marketing, LLC and K. Stephen Tsingas (IN15-5).[74] A fourth case, Oceanside Power, LLC (Oceanside) and Robert Scavo (IN10-5) was resolved prior to an assessment of penalties.

On July 31, 2015, FERC filed a petition in U.S. District Court for the Eastern District of Virginia to enforce its penalty in the Powhatan case.[75] On October 29, 2021, the Houlian Chen case was resolved separately from the rest of the Powhatan Energy, et al., case through an order approving stipulation and consent, which required Houlian Chen to disgorge $600,000.[76] On March 22, 2023, the rest of the Powhatan court case was substantively resolved

70 See PJM Compliance Filing, FERC Docket EL08-14-002 (March 26, 2009).
71 See 128 FERC ¶ 61,262.
72 See 131 FERC ¶ 61,024.
73 See website, "FERC vs. Powhatan Energy Fund, LLC: Legal Materials, Independent Expert Opinions and More," which can be accessed at: <https://ferclitigation.com/>.
74 See 151 FERC 61,179 (2015); 155 FERC ¶ 61,204 (2016); and 152 FERC ¶ 61,012 (2015).
75 See Case No. 3:15-cv-0542.
76 see 177 FERC ¶ 61,076.

by the court's grant of FERC's motion for a default judgment requiring that Powhatan disgorge $3,465,108 and pay a civil penalty of $16,800,000. Because Powhatan filed for bankruptcy on February 26, 2022, and that case remains pending, any payment to FERC will be determined in the bankruptcy proceeding. During the court case, the MMU was subject to a subpoena, including extensive discovery and a deposition. On October 11, 2022, the Coaltrain Energy, L.P., et al., case was resolved through an order approving a stipulation and consent agreement, which provided for Coaltrain to disgorge $4,000,000.[77] The resolution at FERC followed years of litigation by FERC in the U.S. District Court for the Southern District of Ohio seeking to enforce its penalty.[78] The MMU was subject to a subpoena in that proceeding, including a deposition.

On August 22, 2017, the City Power et al. case was resolved through an order approving stipulation and consent agreement, which required Paul Tsingas to disgorge $1,300,000 and pay a penalty of $1,420,000, and City Power pay a civil penalty of $9,000,000.[79]

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

Over a decade of litigation was required to prevail on a matter that, at its core, involved wash trading, a common manipulative scheme. These cases illustrate the limitations of reliance on ex post enforcement mechanisms to prevent market manipulation, including fraudulent schemes and exercise of market power. It is essential to avoid flawed rules in the first instance, and thereby address potential manipulation and exercise of market power ex ante.

Market Performance

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

LMP

The behavior of individual market entities within a market structure is reflected in market prices. PJM locational marginal prices (LMPs) are a direct measure of market performance. Price level is a good, general indicator of market performance, although overall price results must be interpreted carefully because of the multiple factors that affect them. Among other things, overall average prices reflect changes in supply and demand, generation fuel mix, the cost of fuel, emission related expenses, markup and local price differences caused by congestion. PJM also may administratively set prices with the creation of a closed loop interface related to demand side resources, surrogate constraints for reactive power and generator stability, or influence prices through manual interventions such as load biasing, changing constraint limits and penalty factors, and committing reserves beyond the requirement.

The real-time average LMP in the first three months of 2023 decreased 43.1 percent from the first three months of 2022, from $51.95 per MWh to $29.57 per MWh. The real-time load-weighted average LMP in the first three months of 2023 decreased 44.1 percent from the first three months of 2022, from $54.13 per MWh to $30.28 per MWh.

The costs of fuel, emissions, and consumables, fundamental components of the real-time load weighted average LMP, decreased $13.89 per MWh from $36.86 per MWh in the first three months of 2022 to $22.97 per MWh in the first three months of 2023, which accounts for 58.2 percent of the decrease in real-time load-weighted average LMP.

The day-ahead average LMP for the first three months of 2022 decreased 40.2 percent from the first three months of 2022, from $52.25 per MWh to $31.26 per MWh. The day-ahead load-weighted average LMP in the first three months of 2023 decreased 40.7 percent from the first three months of 2022, from $54.23 per MWh to $32.16 per MWh.

77 See 181 FERC ¶ 61,031.
78 Case No. 2:16-cv-732-MHW-KAJ.
79 See 160 FERC ¶ 61,013.

Occasionally, in a constrained market, the LMPs at some pricing nodes can exceed the offer price of the highest cleared generator in the supply curve.[80] In the nodal pricing system, the LMP at a pricing node is the total cost of meeting incremental demand at that node. When there are binding transmission constraints, satisfying the marginal increase in demand at a node may require increasing the output of some generators while simultaneously decreasing the output of other generators, such that the transmission constraints are not violated. The total cost of redispatching multiple generators can at times exceed the cost of marginally increasing the output of the most expensive generator offered. Thus, the LMPs at some pricing nodes exceed $1,000 per MWh, the cap on the generators' offer price in the PJM market.[81]

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

Fast Start Pricing: DLMP and PLMP

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

The pricing run calculates LMP using the same optimal power flow algorithm as the dispatch run while simultaneously ignoring (relaxing) the economic minimum and maximum output MW constraints for all eligible fast start units. Fast start units must have: notification time plus start time are less than or equal to one hour; minimum run time is less than or equal to one hour; and units are online and running for PJM, not self-scheduled. The goal of fast start pricing is to allow inflexible resources to set prices based on the sum of their commitment costs per MWh and their marginal costs.

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

DLMP and PLMP

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

The real-time load-weighted average PLMP was $30.28 per MWh for the first three months of 2023, which is 2.9 percent, $0.85 per MWh, higher than the real-time load-weighted average DLMP of $29.43 per MWh.

The day-ahead load-weighted average PLMP was $32.16 per MWh for the first three months of 2023, which is 0.1 percent, $0.04 per MWh, higher than the day-ahead load-weighted average DLMP of $32.11 per MWh.

80 See O'Neill R. P, Mead D. and Malvadkar P. "On Market Clearing Prices Higher than the Highest Bid and Other Almost Paranormal Phenomena." *The Electricity Journal* 2005; 18(2) at 19–27.

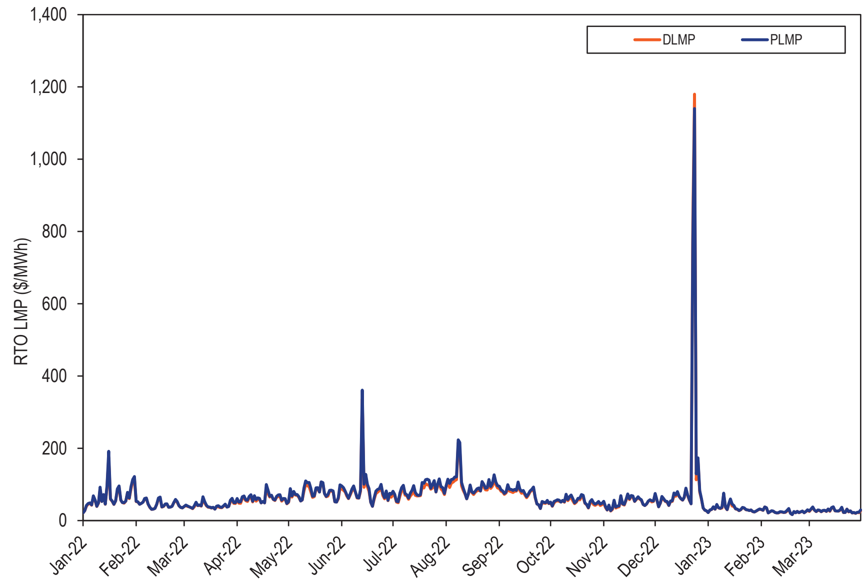
81 The offer cap in PJM was temporarily increased to $1,800 per MWh prior to the winter of 2014/2015. A new cap of $2,000 per MWh, only for offers with costs exceeding $1,000 per MWh, went into effect on December 14, 2015. See 153 FERC ¶ 61,289 (2015).

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

		Day-Ahead Load-Weighted Average				Real-Time Load-Weighted Average			
Year	Month	DLMP	PLMP	Difference	Percent Difference	DLMP	PLMP	Difference	Percent Difference
2022	Jan	$64.57	$64.80	$0.22	0.3%	$66.43	$69.06	$2.64	4.0%
2022	Feb	$49.96	$50.35	$0.39	0.8%	$45.93	$46.76	$0.83	1.8%
2022	Mar	$45.25	$45.50	$0.25	0.6%	$41.83	$43.56	$1.73	4.1%
2022	Apr	$64.10	$64.18	$0.08	0.1%	$60.38	$63.91	$3.52	5.8%
2022	May	$83.17	$83.24	$0.06	0.1%	$79.04	$83.16	$4.12	5.2%
2022	Jun	$90.24	$90.54	$0.29	0.3%	$91.44	$97.89	$6.46	7.1%
2022	Jul	$96.07	$96.38	$0.32	0.3%	$84.03	$92.48	$8.45	10.1%
2022	Aug	$106.18	$106.07	($0.10)	(0.1%)	$105.68	$113.74	$8.06	7.6%
2022	Sep	$82.86	$82.80	($0.06)	(0.1%)	$74.08	$78.29	$4.22	5.7%
2022	Oct	$58.30	$58.37	$0.07	0.1%	$52.27	$55.90	$3.63	6.9%
2022	Nov	$56.29	$55.24	($1.05)	(1.9%)	$50.86	$52.93	$2.07	4.1%
2022	Dec	$93.02	$93.39	$0.37	0.4%	$143.65	$142.22	($1.42)	(1.0%)
2022	Jan - Mar	$53.26	$53.55	$0.29	0.5%	$51.39	$53.13	$1.73	3.4%
2022	Jan - Dec	$75.35	$75.44	$0.08	0.1%	$76.34	$80.14	$3.80	5.0%
2023	Jan	$36.53	$36.58	$0.05	0.1%	$34.66	$35.75	$1.09	3.1%
2023	Feb	$31.16	$31.22	$0.06	0.2%	$25.47	$26.04	$0.57	2.2%
2023	Mar	$28.39	$28.41	$0.02	0.1%	$27.58	$28.42	$0.85	3.1%
2023	Jan - Mar	$32.11	$32.16	$0.04	0.1%	$29.43	$30.28	$0.85	2.9%

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

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



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

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

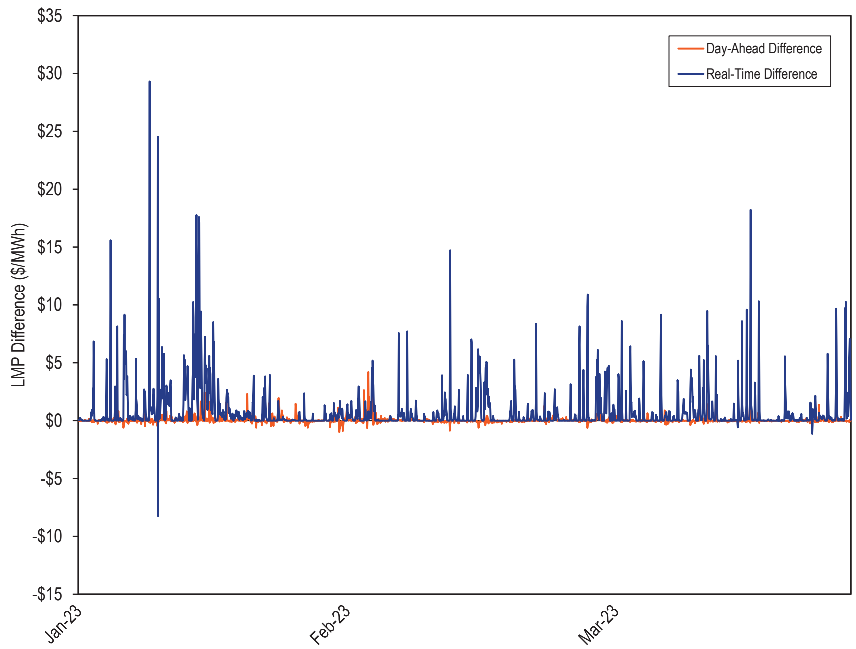


Figure 3-26 shows the hourly average load and LMP difference by hour of the day for the first three months of 2023.

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

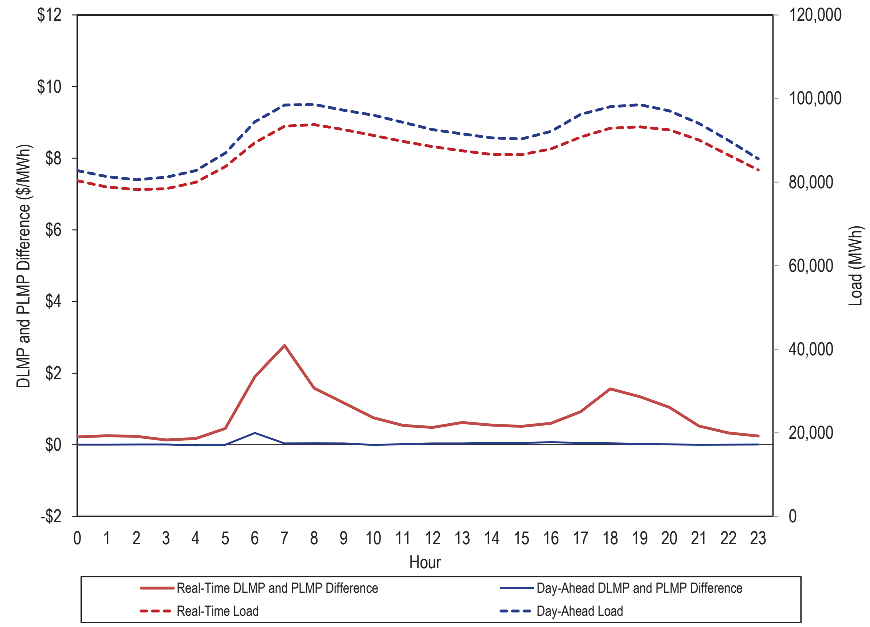


Table 3-32 shows the percent of total marginal units that are fast start units by unit type for 2022 through March 2023. While wind units are defined as fast start units, a wind unit on the margin does not result in a higher PLMP than DLMP when the unit has no commitment costs.

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

		Dispatch Run				Pricing Run			
Year	Month	CT	Diesel	Wind	All Fast Start Units	CT	Diesel	Wind	All Fast Start Units
2022	Jan	1.3%	0.3%	0.2%	1.8%	4.9%	0.9%	0.2%	6.2%
2022	Feb	0.6%	0.2%	0.3%	1.1%	3.2%	0.5%	0.3%	4.0%
2022	Mar	0.5%	0.2%	0.4%	1.1%	3.4%	0.5%	0.4%	4.4%
2022	Apr	0.8%	0.1%	0.1%	1.2%	4.4%	0.3%	0.1%	5.0%
2022	May	1.4%	0.7%	0.1%	2.4%	6.6%	1.2%	0.1%	8.1%
2022	Jun	2.3%	0.3%	0.1%	2.6%	9.3%	0.8%	0.1%	10.2%
2022	Jul	2.7%	0.6%	0.1%	3.3%	16.3%	1.4%	0.0%	17.7%
2022	Aug	2.0%	0.4%	0.0%	2.4%	12.0%	1.3%	0.0%	13.3%
2022	Sep	0.8%	0.3%	0.1%	1.2%	5.6%	1.0%	0.1%	6.7%
2022	Oct	2.2%	0.2%	0.3%	2.6%	6.6%	0.9%	0.2%	7.7%
2022	Nov	1.3%	0.2%	0.2%	1.7%	5.1%	0.9%	0.2%	6.1%
2022	Dec	1.3%	0.7%	0.2%	2.2%	6.3%	1.5%	0.2%	8.0%
2022	Jan - Mar	0.8%	0.2%	0.3%	1.3%	3.9%	0.6%	0.3%	4.9%
2023	Jan	1.6%	0.5%	0.1%	2.1%	6.2%	2.8%	0.0%	9.0%
2023	Feb	0.9%	0.2%	0.0%	1.1%	3.1%	0.6%	0.0%	3.7%
2023	Mar	0.8%	0.4%	0.1%	1.2%	3.0%	0.7%	0.1%	3.8%
2023	Jan - Mar	1.1%	0.4%	0.1%	1.5%	4.1%	1.4%	0.0%	5.5%

Table 3-33 shows the difference between day-ahead and real-time zonal average DLMP and PLMP for the first three months of 2023. The average difference in real-time prices in DPL was $1.10 per MWh, 4.0 percent, while the average difference in real-time prices in PECO was $0.59 per MWh, 2.4 percent.

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

	2023 (Jan-Mar)							
	Day-Ahead				Real-Time			
Zone	Average DLMP	Average PLMP	Difference	Percent Difference	Average DLMP	Average PLMP	Difference	Percent Difference
ACEC	$28.15	$28.18	$0.02	0.1%	$25.88	$26.53	$0.65	2.5%
AEP	$31.41	$31.45	$0.05	0.1%	$29.09	$29.89	$0.80	2.7%
APS	$32.58	$32.60	$0.03	0.1%	$29.61	$30.47	$0.86	2.9%
ATSI	$31.54	$31.59	$0.05	0.2%	$29.00	$29.80	$0.80	2.8%
BGE	$36.48	$36.52	$0.04	0.1%	$31.60	$32.51	$0.91	2.9%
COMED	$26.77	$26.81	$0.04	0.2%	$25.63	$26.35	$0.72	2.8%
DAY	$32.76	$32.81	$0.05	0.1%	$30.33	$31.15	$0.82	2.7%
DUKE	$31.97	$32.02	$0.05	0.1%	$29.61	$30.42	$0.81	2.7%
DOM	$34.66	$34.69	$0.03	0.1%	$32.35	$33.20	$0.85	2.6%
DPL	$29.08	$29.17	$0.09	0.3%	$27.37	$28.47	$1.10	4.0%
DUQ	$30.86	$30.91	$0.05	0.2%	$28.65	$29.44	$0.79	2.7%
EKPC	$31.50	$31.55	$0.05	0.1%	$29.39	$30.19	$0.80	2.7%
JCPLC	$28.59	$28.61	$0.02	0.1%	$26.21	$26.86	$0.65	2.5%
MEC	$31.29	$31.32	$0.03	0.1%	$28.13	$29.00	$0.86	3.1%
OVEC	$31.03	$31.07	$0.05	0.1%	$28.96	$29.75	$0.79	2.7%
PECO	$27.02	$27.05	$0.02	0.1%	$25.01	$25.60	$0.59	2.4%
PE	$31.93	$31.90	($0.03)	(0.1%)	$28.52	$29.34	$0.81	2.8%
PEPCO	$35.48	$35.51	$0.03	0.1%	$30.85	$31.74	$0.90	2.9%
PPL	$29.01	$29.04	$0.03	0.1%	$26.35	$27.01	$0.66	2.5%
PSEG	$29.21	$29.23	$0.02	0.1%	$26.44	$27.10	$0.65	2.5%
REC	$31.07	$31.09	$0.02	0.1%	$27.79	$28.48	$0.69	2.5%

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

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

	2023 (Jan-Mar)							
	Day-Ahead				Real-Time			
Hub	Average DLMP	Average PLMP	Difference	Percent Difference	Average DLMP	Average PLMP	Difference	Percent Difference
AEP GEN HUB	$30.59	$30.64	$0.05	0.2%	$28.40	$29.19	$0.80	2.8%
AEP-DAYTON HUB	$31.01	$31.05	$0.05	0.1%	$28.81	$29.60	$0.79	2.7%
ATSI GEN HUB	$30.78	$30.83	$0.05	0.2%	$28.25	$29.05	$0.80	2.8%
CHICAGO GEN HUB	$26.43	$26.47	$0.04	0.2%	$25.27	$25.98	$0.72	2.8%
CHICAGO HUB	$26.85	$26.89	$0.04	0.1%	$25.71	$26.43	$0.72	2.8%
DOMINION HUB	$33.65	$33.69	$0.04	0.1%	$30.73	$31.57	$0.85	2.8%
EASTERN HUB	$29.43	$29.50	$0.07	0.3%	$27.38	$28.46	$1.08	4.0%
N ILLINOIS HUB	$26.68	$26.72	$0.04	0.1%	$25.54	$26.26	$0.71	2.8%
NEW JERSEY HUB	$28.80	$28.83	$0.02	0.1%	$26.25	$26.90	$0.65	2.5%
OHIO HUB	$30.88	$30.92	$0.05	0.1%	$28.69	$29.47	$0.78	2.7%
WEST INT HUB	$32.01	$32.05	$0.04	0.1%	$29.36	$30.16	$0.80	2.7%
WESTERN HUB	$33.13	$33.13	($0.00)	(0.0%)	$29.31	$30.13	$0.82	2.8%

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

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

	2023 (Jan - Mar)									
Zone	< ($50)	($50) to ($10)	($10) to $0	$0	$0 to $10	$10 to $20	$20 to $50	$50 to $100	$100 to $200	>= $200
PJM-RTO	0.0%	0.0%	0.4%	56.0%	42.3%	1.0%	0.3%	0.0%	0.0%	0.0%
ACEC	0.0%	0.0%	5.3%	56.4%	37.0%	0.9%	0.2%	0.0%	0.0%	0.0%
AEP	0.0%	0.0%	0.7%	56.5%	41.5%	1.0%	0.3%	0.0%	0.0%	0.0%
APS	0.0%	0.0%	0.7%	56.3%	41.5%	1.1%	0.3%	0.0%	0.0%	0.0%
ATSI	0.0%	0.0%	0.6%	56.1%	42.0%	1.0%	0.3%	0.0%	0.0%	0.0%
BGE	0.0%	0.0%	4.3%	56.0%	38.1%	1.1%	0.4%	0.1%	0.0%	0.0%
COMED	0.0%	0.0%	1.1%	56.6%	41.1%	0.8%	0.3%	0.0%	0.0%	0.0%
DAY	0.0%	0.0%	0.6%	56.3%	41.7%	1.0%	0.3%	0.0%	0.0%	0.0%
DUKE	0.0%	0.0%	0.7%	56.5%	41.5%	0.9%	0.3%	0.0%	0.0%	0.0%
DOM	0.0%	0.0%	2.0%	56.3%	40.1%	1.1%	0.3%	0.1%	0.0%	0.0%
DPL	0.0%	0.0%	6.9%	56.4%	34.8%	0.9%	0.3%	0.4%	0.4%	0.0%
DUQ	0.0%	0.0%	0.7%	56.1%	41.9%	1.0%	0.3%	0.0%	0.0%	0.0%
EKPC	0.0%	0.0%	0.8%	56.4%	41.5%	0.9%	0.3%	0.0%	0.0%	0.0%
JCPLC	0.0%	0.0%	4.0%	56.4%	38.5%	0.9%	0.2%	0.0%	0.0%	0.0%
MEC	0.0%	0.0%	2.0%	55.9%	40.2%	1.5%	0.4%	0.0%	0.0%	0.0%
OVEC	0.0%	0.0%	0.9%	56.5%	41.3%	0.9%	0.3%	0.0%	0.0%	0.0%
PECO	0.0%	0.0%	6.9%	56.3%	35.6%	0.9%	0.2%	0.0%	0.0%	0.0%
PE	0.0%	0.0%	0.7%	55.9%	42.0%	1.1%	0.3%	0.0%	0.0%	0.0%
PEPCO	0.0%	0.0%	2.5%	56.3%	39.6%	1.1%	0.4%	0.1%	0.0%	0.0%
PPL	0.0%	0.0%	4.3%	56.0%	38.5%	0.8%	0.2%	0.0%	0.0%	0.0%
PSEG	0.0%	0.0%	3.5%	56.3%	39.1%	0.9%	0.2%	0.0%	0.0%	0.0%
REC	0.0%	0.0%	3.3%	56.1%	39.4%	0.9%	0.3%	0.0%	0.0%	0.0%

Real-Time Average LMP

Real-time average LMP is the hourly average LMP for the PJM Real-Time Energy Market.[82]

PJM Real-Time Average LMP

Table 3-36 shows the real-time average LMP for the first three months of 1998 through 2023.[83] The real-time average LMP in the first three months of 2023 decreased $22.38 per MWh, or 43.1 percent from 2022, from $51.95 per MWh to $29.57 per MWh.

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

	Real-Time LMP			Year to Year Change			
Jan-Mar	Average	Median	Standard Deviation	Average	Average Percent	Median	Standard Deviation
1998	$17.51	$15.30	$7.84	NA	NA	NA	NA
1999	$18.79	$16.56	$7.29	$1.28	7.3%	8.3%	(7.0%)
2000	$23.66	$17.73	$16.22	$4.87	25.9%	7.0%	122.4%
2001	$33.77	$26.01	$20.79	$10.12	42.8%	46.8%	28.2%
2002	$22.23	$19.22	$9.61	($11.54)	(34.2%)	(26.1%)	(53.8%)
2003	$49.57	$43.08	$30.54	$27.34	123.0%	124.2%	217.9%
2004	$46.37	$41.04	$24.07	($3.20)	(6.5%)	(4.8%)	(21.2%)
2005	$46.51	$40.62	$22.07	$0.14	0.3%	(1.0%)	(8.3%)
2006	$52.98	$46.15	$23.29	$6.47	13.9%	13.6%	5.5%
2007	$55.34	$47.15	$33.29	$2.36	4.5%	2.2%	43.0%
2008	$66.75	$57.05	$35.54	$11.41	20.6%	21.0%	6.8%
2009	$47.29	$40.56	$21.99	($19.46)	(29.2%)	(28.9%)	(38.1%)
2010	$44.13	$37.82	$21.87	($3.16)	(6.7%)	(6.8%)	(0.6%)
2011	$44.76	$38.14	$23.10	$0.63	1.4%	0.8%	5.6%
2012	$30.38	$28.82	$11.63	($14.37)	(32.1%)	(24.4%)	(49.7%)
2013	$36.33	$32.29	$18.47	$5.95	19.6%	12.1%	58.9%
2014	$84.04	$48.77	$119.84	$47.71	131.3%	51.0%	548.8%
2015	$47.39	$31.95	$42.42	($36.65)	(43.6%)	(34.5%)	(64.6%)
2016	$25.60	$22.91	$12.99	($21.79)	(46.0%)	(28.3%)	(69.4%)
2017	$29.39	$25.71	$12.28	$3.79	14.8%	12.2%	(5.4%)
2018	$44.65	$26.83	$49.68	$15.27	51.9%	4.4%	304.5%
2019	$29.13	$25.36	$15.09	($15.53)	(34.8%)	(5.5%)	(69.6%)
2020	$19.42	$18.56	$6.98	($9.71)	(33.3%)	(26.8%)	(53.8%)
2021	$29.78	$23.66	$23.91	$10.36	53.4%	27.5%	242.6%
2022	$51.95	$43.28	$36.57	$22.17	74.5%	82.9%	53.0%
2023	$29.57	$26.50	$18.55	($22.38)	(43.1%)	(38.8%)	(49.3%)

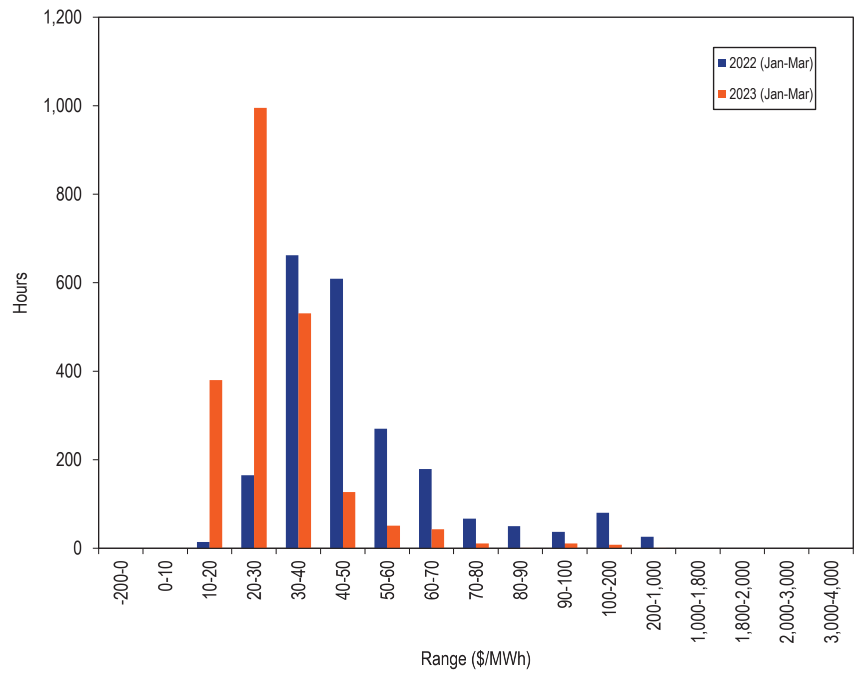
82 See the *Technical Reference for PJM Markets*, at "Calculating Locational Marginal Price," p 16-18 for detailed definition of Real-Time LMP. <http://www.monitoringanalytics.com/reports/Technical_References/references.shtml>.

83 The system average LMP is the average of the hourly LMP without any weighting. The only exception is that market-clearing prices (MCPs) are included for January to April 1998. MCP was the single market-clearing price calculated by PJM prior to implementation of LMP.

PJM Real-Time Average LMP Duration

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

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



Real-Time Load-Weighted Average LMP

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

PJM Real-Time Load-Weighted Average LMP

Table 3-37 shows the real-time load-weighted average LMP for the first three months of 1998 through 2023. The real-time load-weighted average LMP in the first three months of 2023 decreased $23.85 per MWh, or 44.1 percent from the first three months of 2022, from $54.13 per MWh to $30.28 per MWh.

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

	Real-Time Load-Weighted Average LMP			Year to Year Change			
Jan-Mar	Average	Median	Standard Deviation	Average	Average Percent	Median	Standard Deviation
1998	$18.13	$15.80	$8.14	NA	NA	NA	NA
1999	$19.38	$16.90	$7.66	$1.25	6.9%	7.0%	(5.9%)
2000	$25.10	$18.25	$17.22	$5.72	29.5%	8.0%	124.9%
2001	$35.16	$27.38	$21.52	$10.06	40.1%	50.0%	25.0%
2002	$23.01	$19.89	$9.93	($12.15)	(34.6%)	(27.4%)	(53.8%)
2003	$51.93	$46.12	$30.99	$28.91	125.6%	131.9%	211.9%
2004	$48.77	$43.22	$24.62	($3.16)	(6.1%)	(6.3%)	(20.6%)
2005	$48.37	$42.20	$22.62	($0.40)	(0.8%)	(2.4%)	(8.1%)
2006	$54.43	$47.62	$23.69	$6.05	12.5%	12.9%	4.7%
2007	$58.07	$50.60	$34.44	$3.65	6.7%	6.3%	45.4%
2008	$69.35	$60.11	$36.56	$11.28	19.4%	18.8%	6.2%
2009	$49.60	$42.23	$23.38	($19.76)	(28.5%)	(29.8%)	(36.1%)
2010	$45.92	$39.01	$22.99	($3.68)	(7.4%)	(7.6%)	(1.7%)
2011	$46.35	$39.11	$24.26	$0.43	0.9%	0.3%	5.5%
2012	$31.21	$29.25	$12.02	($15.15)	(32.7%)	(25.2%)	(50.5%)
2013	$37.41	$32.79	$19.90	$6.21	19.9%	12.1%	65.7%
2014	$92.98	$51.62	$134.40	$55.57	148.5%	57.4%	575.3%
2015	$50.91	$33.51	$46.43	($42.07)	(45.2%)	(35.1%)	(65.5%)
2016	$26.80	$23.45	$13.98	($24.11)	(47.4%)	(30.0%)	(69.9%)
2017	$30.28	$26.26	$13.08	$3.48	13.0%	12.0%	(6.4%)
2018	$49.45	$27.96	$55.22	$19.17	63.3%	6.5%	322.1%
2019	$30.16	$25.84	$16.18	($19.29)	(39.0%)	(7.6%)	(70.7%)
2020	$19.85	$18.87	$7.20	($10.31)	(34.2%)	(27.0%)	(55.5%)
2021	$30.84	$24.13	$24.58	$10.99	55.3%	27.9%	241.3%
2022	$54.13	$44.32	$38.74	$23.29	75.5%	83.7%	57.6%
2023	$30.28	$27.19	$19.80	($23.85)	(44.1%)	(38.7%)	(48.9%)

PJM Real-Time Monthly Load-Weighted Average LMP

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

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

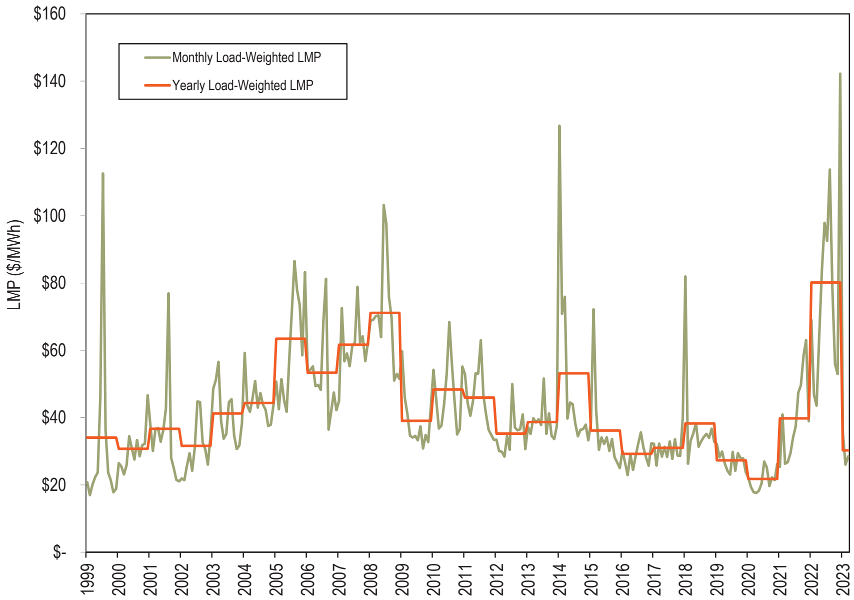


Table 3-38 shows the real-time monthly on peak and off peak load-weighted average LMP for 2022 through March 2023.

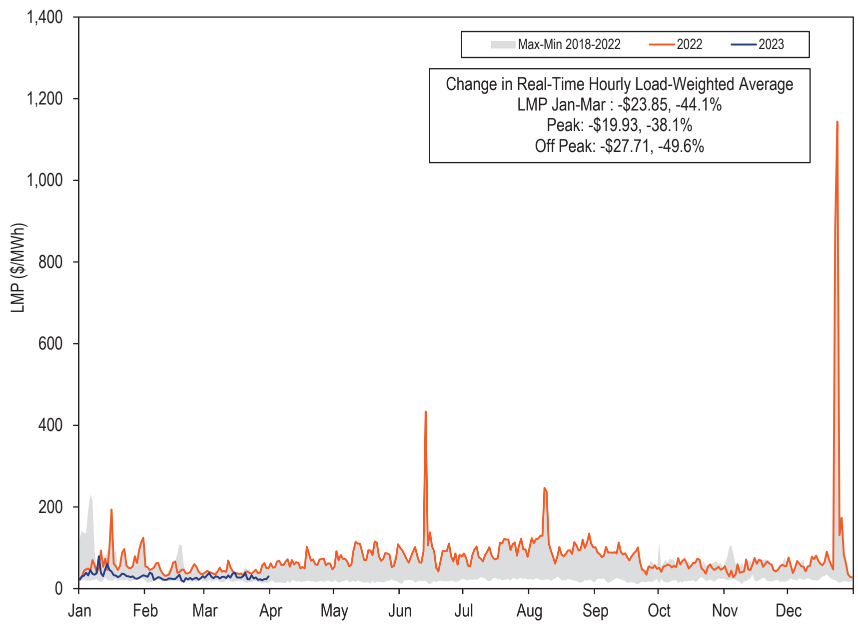
Table 3-38 Real-time monthly on peak and off peak load-weighted average LMP (Dollars per MWh): 2022 through March 2023

	2022				2023			
	Off Peak	On Peak	Difference	Percent Difference	Off Peak	On Peak	Difference	Percent Difference
Jan	$74.99	$62.54	($12.46)	(16.6%)	$33.20	$38.53	$5.32	16.0%
Feb	$45.70	$47.86	$2.16	4.7%	$23.45	$28.67	$5.22	22.3%
Mar	$41.58	$45.41	$3.83	9.2%	$26.96	$29.78	$2.82	10.5%
Apr	$55.93	$71.89	$15.96	28.5%				
May	$66.12	$100.85	$34.73	52.5%				
Jun	$61.63	$126.83	$65.20	105.8%				
Jul	$71.83	$114.13	$42.31	58.9%				
Aug	$85.89	$136.31	$50.42	58.7%				
Sep	$66.36	$89.76	$23.40	35.3%				
Oct	$47.61	$64.50	$16.90	35.5%				
Nov	$45.48	$60.50	$15.01	33.0%				
Dec	$153.54	$129.51	($24.03)	(15.7%)				

PJM Real-Time Daily Load-Weighted Average LMP

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

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



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

Figure 3-30 shows the PJM real-time monthly load-weighted average LMP and inflation adjusted monthly load-weighted average LMP from January 1998 through March 2023.[84] Table 3-39 shows the PJM real-time load-weighted average LMP and inflation adjusted load-weighted average LMP for the first three months of every year from 1998 through 2023.

84 To obtain the inflation adjusted, monthly, load-weighted, average LMP, the PJM system-wide load-weighted average LMP is deflated using the US Consumer Price Index for all items, Urban Consumers (base period: January 1998), published by *Bureau of Labor* Statistics. <http://download.bls.gov/pub/time.series/cu/cu.data.1.AllItems> (Accessed January 12, 2023)

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

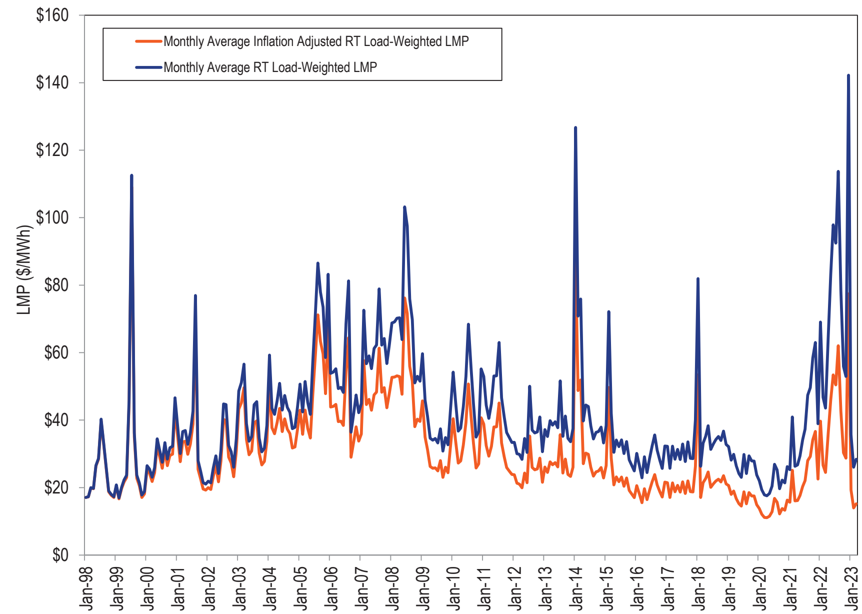


Table 3-39 Real-time load-weighted and inflation adjusted load-weighted average LMP: January through March, 1998 through 2023

	Load-Weighted Average LMP	Inflation Adjusted Load-Weighted Average LMP
	Jan-Mar	Jan-Mar
1998	$18.13	$18.10
1999	$19.38	$19.03
2000	$25.10	$23.89
2001	$35.16	$32.35
2002	$23.01	$20.90
2003	$51.93	$45.86
2004	$48.77	$42.36
2005	$48.37	$40.73
2006	$54.43	$44.21
2007	$58.07	$46.05
2008	$69.35	$52.85
2009	$49.60	$37.83
2010	$45.92	$34.21
2011	$46.35	$33.83
2012	$31.21	$22.14
2013	$37.41	$26.09
2014	$92.98	$64.01
2015	$50.91	$35.04
2016	$26.80	$18.25
2017	$30.28	$20.11
2018	$49.45	$32.17
2019	$30.16	$19.28
2020	$19.85	$12.42
2021	$30.84	$18.94
2022	$54.13	$30.86
2023	$30.28	$16.29

Real-Time Dispatch and Pricing

On November 1, 2021, PJM implemented a new real-time dispatch process that aligned the timing of dispatch and pricing in the real-time energy market. The PJM Real-Time Energy Market is based on applications that produce the generator dispatch for energy and reserves, and five minute locational marginal prices (LMPs). These applications include the real-time security constrained economic dispatch (RT SCED), the locational pricing calculator (LPC), and the ancillary services optimizer (ASO).[85] The final real-time LMPs and ancillary service clearing prices are determined for every five minute interval by LPC.

Real-Time SCED and LPC

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

Table 3-40 shows the number of RT SCED case solutions, the number of solutions that were approved, and the number and percent of approved solutions used in LPC. The RT SCED execution frequency is once every five

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

minutes. PJM operators have the ability to execute additional RT SCED cases. Each execution of RT SCED produces five solutions, using five different levels of load bias. Since prices are calculated every five minutes while five SCED solutions are produced every five minutes, there is, by definition, a larger number of SCED solutions than there are five minute intervals in any given period.

Table 3-40 shows that in the first three months of 2023, 97.8 percent of approved RT SCED solutions that were used to send dispatch signals to generators were used in calculating real-time energy market prices, compared to 96.5 percent in all of 2022.

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

	2022				2023			
Month	Number of RT SCED Solutions	Number of Approved RT SCED Solutions	Number of Approved RT SCED Solutions Used in LPC	RT SCED Solutions Used in LPC as Percent of Approved RT SCED Solutions	Number of RT SCED Solutions	Number of Approved RT SCED Solutions	Number of Approved RT SCED Solutions Used in LPC	RT SCED Solutions Used in LPC as Percent of Approved RT SCED Solutions
Jan	46,494	9,035	8,846	97.9%	45,175	9,075	8,900	98.1%
Feb	41,456	8,281	8,001	96.6%	40,924	8,225	7,987	97.1%
Mar	45,704	9,296	8,863	95.3%	44,876	9,016	8,861	98.3%
Apr	44,155	8,832	8,566	97.0%				
May	45,385	9,118	8,862	97.2%				
Jun	43,995	8,900	8,605	96.7%				
Jul	45,453	9,151	8,879	97.0%				
Aug	45,161	9,395	8,869	94.4%				
Sep	43,623	8,956	8,523	95.2%				
Oct	45,384	9,041	8,779	97.1%				
Nov	44,080	9,000	8,594	95.5%				
Dec	45,334	8,967	8,822	98.4%				
Total	536,224	107,972	104,209	96.5%	130,975	26,316	25,748	97.8%

Until November 1, 2021, PJM did not link dispatch and settlement intervals. RT SCED moved from automatically executing a case every three minutes to every five minutes in 2020, while settlements are linked to five minute intervals. Until November 1, 2021, RT SCED solved the dispatch problem for a target time that was generally 14 minutes in the future. An RT SCED case was approved and sent dispatch signals to generators based on a 10 minute ramp time. The look ahead time for the load forecast and the look ahead time for the resource dispatch target did not match, and a new RT SCED case would override the previously approved case before resources had time to achieve the previous target dispatch. Prior to October 15, 2020, the interval that was priced in LPC was consistently before the target time from the RT SCED case used for the dispatch signal. LPC took the most recently approved RT SCED case to calculate LMPs for the present five minute interval. For example, the LPC case that calculated prices for the interval ending 1005 EPT used an approved RT SCED case that sent MW dispatch signals for the target time of 1010 EPT. This discrepancy created a mismatch between the MW dispatch and real-time LMPs and undermined generators' incentive to follow dispatch. Under new RT SCED changes that were implemented on October 15, 2020, PJM resolved the mismatch between LPC and the RT SCED target time, but prices no longer applied at the time when resources received and followed that dispatch signal.[86] For example, the LPC case that calculated prices for the interval ending 1005 EPT used an approved RT SCED case that sent MW dispatch signals at 955 EPT which were no longer effective from 1000 to 1005 EPT. In the first 10 months of 2021, there was a mismatch between the MW dispatch and real-time LMPs that undermined generators' incentive to follow dispatch. The timing remained incorrect until all three (the pricing interval, the dispatch interval, and the RT SCED target time) all corresponded to one another, which PJM implemented on November 1, 2021.

The extent to which dispatch instructions from approved SCED solutions are reflected in concurrent prices in the PJM Real-Time Energy Market can be measured by comparing the start and end times when the dispatch instructions from the RT SCED solution were effective with the start and end times when

86 See Docket No. ER19-2573-000.

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

Table 3-41 shows the average duration of the period when dispatch instructions corresponded to the prevailing prices. Prior to October 15, 2020, PJM used the latest approved RT SCED solution available at the time of LPC execution, regardless of the SCED target time, to calculate prices for the current five minute pricing interval. The average duration of correspondence ranged from 3 minutes 11 seconds to 3 minutes 37 seconds from January through October 15, 2020, varying with changes to the frequency of automatic RT SCED execution. The percent of time that prices were consistent with the dispatch instructions was 67.2 to 69.9 percent, on average. This was far from the goal of 100 percent correspondence between five minute dispatch instructions and prices. With the short term changes to RT SCED that were implemented on October 15, 2020, the prices no longer corresponded to the dispatch instructions. Table 3-41 shows that during the first 10 months of 2021, the dispatch instructions were consistent with prevailing prices for only 33 seconds. During this period, the percent of time that prices were consistent with the dispatch instructions was 9.0 percent. In the period beginning November 1, 2021, PJM aligned the dispatch and pricing intervals such that the prices that were effective for each five minute interval were generally based on the RT SCED case that sent dispatch signals with the target time at the end of the five minute interval. As a result of these changes, in 2022, the dispatch instructions were consistent with the prices on average for 4 minutes and 45 seconds out of each five minute interval, or 95.7 percent of each five minute interval. In the first three months of 2023, the dispatch instructions were consistent with prices on average for 4 minutes and 47 seconds out of each five minute interval, or 96.0 percent of each five minute interval.

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

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

Recalculation of Five Minute Real-Time Prices

PJM's five minute interval LMPs are obtained from solved LPC cases. PJM recalculates five minute interval real-time LMPs as it believes necessary to correct errors. To do so, PJM reruns LPC cases with modified inputs. The PJM OATT allows for posting of recalculated real-time prices no later than 1700 (EPT) of the tenth calendar day following the operating day. The OATT also requires PJM to notify market participants of the underlying error no later than 1700 (EPT) of the second business day following the operating day.[87] Table 3-42 shows the number of five minute intervals in each month and number of five minute intervals in each month for which PJM recalculated real-time prices in 2022 and first three months of 2023. In the first three months of 2023, PJM recalculated LMPs for 450 five minute intervals or 1.74 percent of the total 25,908 five minute intervals.

87 OA Schedule 1 § 1.10.8(e).

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

	2022 (Jan - Mar)		2023 (Jan - Mar)	
Month	Number of Five Minute Intervals	Number of Five Minute Intervals for Which LMPs Were Recalculated	Number of Five Minute Intervals	Number of Five Minute Intervals for Which LMPs Were Recalculated
January	8,928	179	8,928	161
February	8,064	663	8,064	166
March	8,916	361	8,916	123
April	8,640	345	-	-
May	8,928	188	-	-
June	8,640	170	-	-
July	8,928	218	-	-
August	8,928	339	-	-
September	8,640	343	-	-
October	8,928	364	-	-
November	8,652	254	-	-
December	8,928	211	-	-
Total	105,120	3,635	25,908	450

Day-Ahead Average LMP

Day-ahead average LMP is the hourly average LMP for the PJM Day-Ahead Energy Market.[88]

PJM Day-Ahead Average LMP

Table 3-43 shows the day-ahead average LMP for the first three months of 2001 through 2023. The day-ahead average LMP for the first three months of 2023 decreased $20.99 per MWh, or 40.2 percent from the first three months of 2022, from $52.25 per MWh to $31.26 per MWh.

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

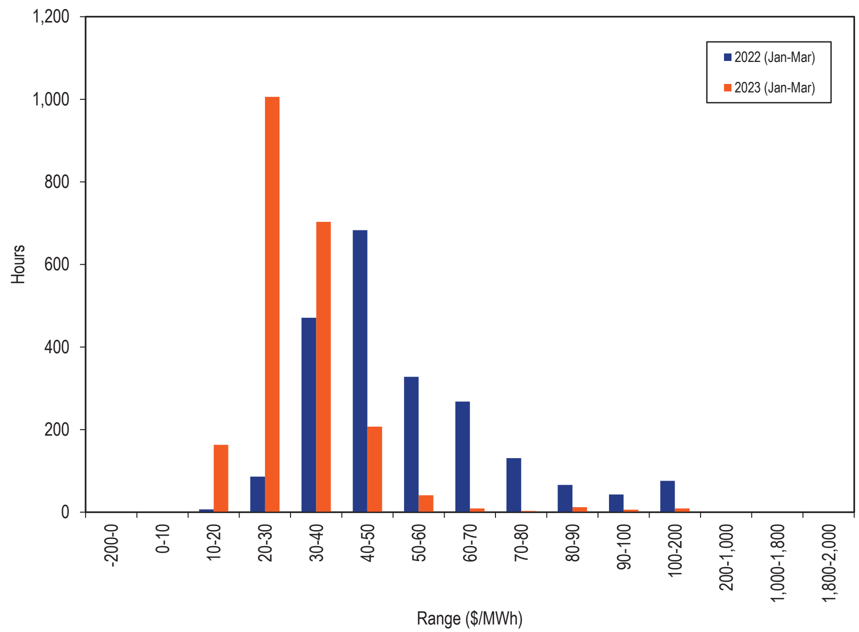
	Day-Ahead LMP			Year to Year Change			
Jan-Mar	Average	Median	Standard Deviation	Average	Average Percent	Median	Standard Deviation
2001	$36.45	$32.72	$16.39	NA	NA	NA	NA
2002	$22.43	$20.59	$7.56	($14.02)	(38.5%)	(37.1%)	(53.9%)
2003	$51.20	$46.06	$25.65	$28.77	128.2%	123.7%	239.3%
2004	$45.84	$43.01	$18.85	($5.36)	(10.5%)	(6.6%)	(26.5%)
2005	$45.14	$41.56	$16.19	($0.70)	(1.5%)	(3.4%)	(14.1%)
2006	$51.23	$48.53	$14.16	$6.08	13.5%	16.8%	(12.6%)
2007	$52.76	$49.43	$22.59	$1.54	3.0%	1.9%	59.5%
2008	$66.10	$62.57	$23.90	$13.34	25.3%	26.6%	5.8%
2009	$47.41	$43.43	$16.85	($18.69)	(28.3%)	(30.6%)	(29.5%)
2010	$46.13	$41.99	$15.93	($1.28)	(2.7%)	(3.3%)	(5.5%)
2011	$45.60	$41.10	$16.82	($0.54)	(1.2%)	(2.1%)	5.6%
2012	$30.82	$30.04	$6.63	($14.78)	(32.4%)	(26.9%)	(60.6%)
2013	$36.46	$34.45	$9.78	$5.65	18.3%	14.7%	47.5%
2014	$86.52	$52.80	$92.80	$50.06	137.3%	53.3%	848.8%
2015	$48.62	$35.48	$36.77	($37.90)	(43.8%)	(32.8%)	(60.4%)
2016	$26.90	$25.11	$8.83	($21.73)	(44.7%)	(29.2%)	(76.0%)
2017	$29.59	$27.33	$8.54	$2.70	10.0%	8.8%	(3.3%)
2018	$43.59	$29.01	$38.64	$14.00	47.3%	6.2%	352.5%
2019	$29.65	$26.82	$11.28	($13.94)	(32.0%)	(7.6%)	(70.8%)
2020	$19.66	$19.14	$4.43	($9.98)	(33.7%)	(28.6%)	(60.7%)
2021	$30.28	$25.44	$18.64	$10.62	54.0%	32.9%	320.9%
2022	$52.25	$46.67	$19.40	$21.97	72.5%	83.4%	4.1%
2023	$31.26	$29.08	$12.18	($20.99)	(40.2%)	(37.7%)	(37.2%)

88 See the *MMU Technical Reference for the PJM Markets*, at "Calculating Locational Marginal Price" for a detailed definition of day-ahead LMP. <http://www.monitoringanalytics.com/reports/Technical_References/references.shtml>.

PJM Day-Ahead Average LMP Duration

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

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



Day-Ahead Load-Weighted Average LMP

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

PJM Day-Ahead Load-Weighted Average LMP

Table 3-44 shows the day-ahead load-weighted average LMP for the first three months of 2001 through 2023. The day-ahead load-weighted average LMP in the first three months of 2023 decreased $22.07, or 40.7 percent from the first three months of 2022, from $54.23 per MWh to $32.16 per MWh.

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

	Day-Ahead Load-Weighted Average LMP			Year to Year Change			
Jan-Mar	Average	Median	Standard Deviation	Average	Average Percent	Median	Standard Deviation
2001	$37.70	$34.55	$16.66	NA	NA	NA	NA
2002	$23.17	$21.18	$7.76	($14.53)	(38.5%)	(38.7%)	(53.4%)
2003	$53.16	$48.69	$25.75	$29.99	129.5%	129.9%	231.7%
2004	$47.75	$45.02	$19.19	($5.41)	(10.2%)	(7.5%)	(25.4%)
2005	$46.54	$42.88	$16.46	($1.21)	(2.5%)	(4.8%)	(14.2%)
2006	$52.40	$49.51	$14.29	$5.86	12.6%	15.5%	(13.2%)
2007	$54.87	$51.89	$23.16	$2.48	4.7%	4.8%	62.0%
2008	$68.00	$64.70	$24.35	$13.13	23.9%	24.7%	5.1%
2009	$49.44	$44.85	$17.54	($18.56)	(27.3%)	(30.7%)	(28.0%)
2010	$47.77	$43.62	$16.52	($1.67)	(3.4%)	(2.7%)	(5.8%)
2011	$47.14	$42.49	$17.73	($0.63)	(1.3%)	(2.6%)	7.3%
2012	$31.51	$30.44	$6.83	($15.64)	(33.2%)	(28.3%)	(61.5%)
2013	$37.26	$35.02	$10.26	$5.75	18.3%	15.0%	50.3%
2014	$94.97	$56.53	$102.23	$57.71	154.9%	61.4%	896.7%
2015	$52.02	$36.94	$40.10	($42.95)	(45.2%)	(34.7%)	(60.8%)
2016	$27.94	$25.99	$9.28	($24.08)	(46.3%)	(29.6%)	(76.8%)
2017	$30.40	$27.99	$8.98	$2.46	8.8%	7.7%	(3.3%)
2018	$47.55	$30.24	$42.58	$17.15	56.4%	8.0%	374.2%
2019	$30.76	$27.28	$12.56	($16.80)	(35.3%)	(9.8%)	(70.5%)
2020	$20.12	$19.54	$4.54	($10.64)	(34.6%)	(28.4%)	(63.9%)
2021	$31.58	$26.11	$20.01	$11.46	57.0%	33.6%	341.0%
2022	$54.23	$48.68	$20.18	$22.65	71.7%	86.4%	0.8%
2023	$32.16	$29.59	$13.25	($22.07)	(40.7%)	(39.2%)	(34.3%)

PJM Day-Ahead Monthly Load-Weighted Average LMP

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

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

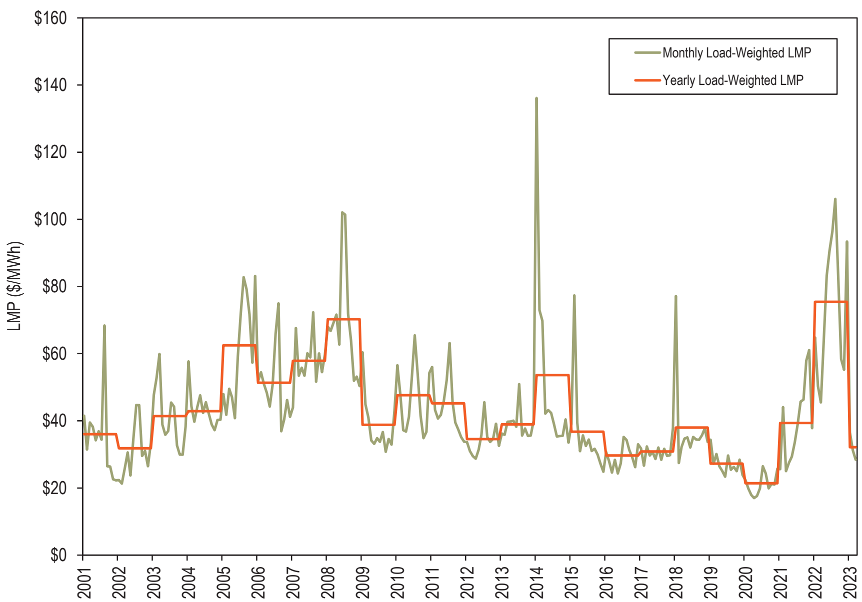
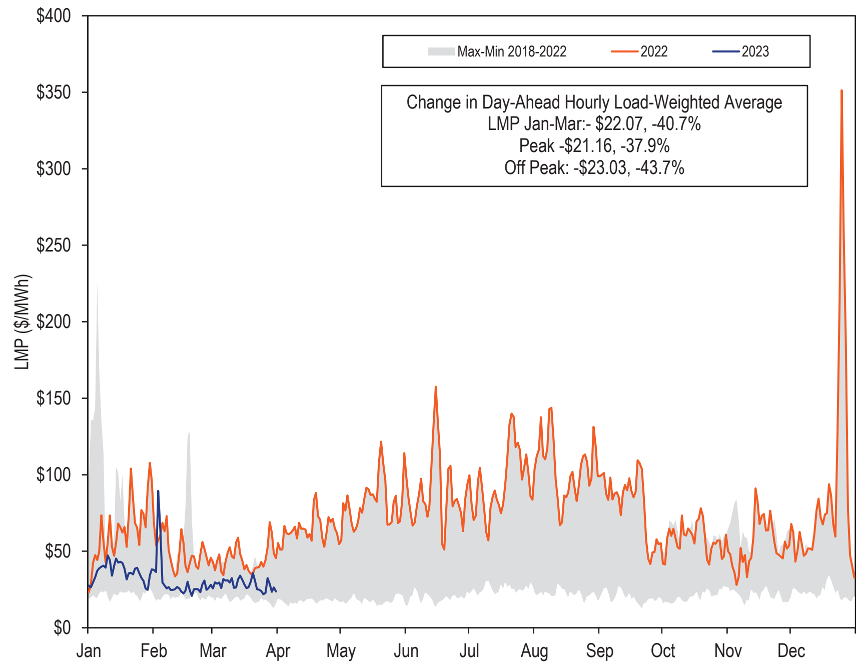


Figure 3-33 shows the day-ahead daily load-weighted average LMP in 2022 through March 2023 compared to the historic five year price range.

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



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

Figure 3-34 shows the PJM day-ahead monthly load-weighted average LMP and inflation adjusted monthly day-ahead load-weighted average LMP for June 2000 through March 2023.[89] Table 3-45 shows the PJM day-ahead load-weighted average LMP and inflation adjusted load-weighted average LMP for the first three months of every year from 2001 through 2023.

89 To obtain the inflation adjusted monthly load-weighted average LMP, the PJM system-wide load-weighted average LMP is deflated using US Consumer Price Index for all items, Urban Consumers (base period: January 1998), published by *Bureau of Labor Statistics*. <http://download.bls.gov/pub/time.series/cu/cu.data.1.AllItems> (Accessed January 12, 2023).

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

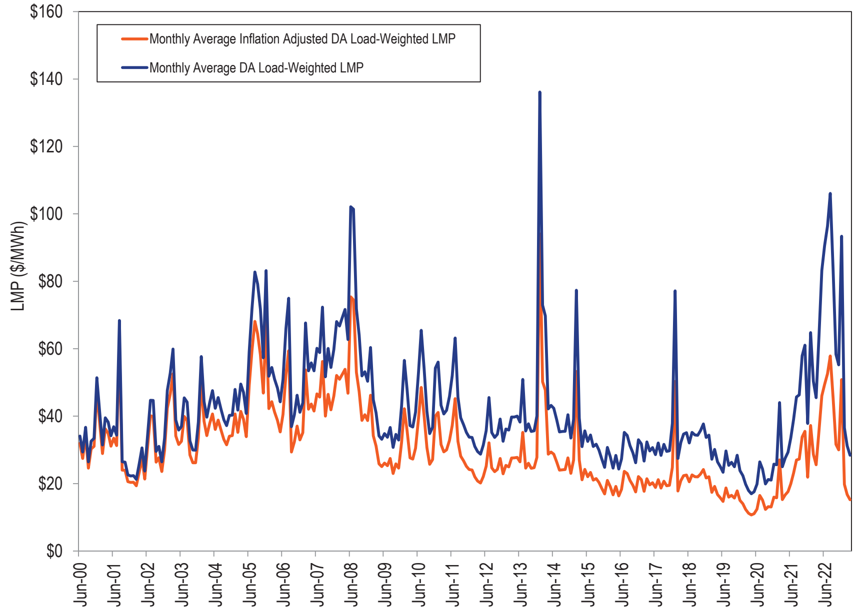


Table 3-45 Day-ahead yearly load-weighted and inflation adjusted load-weighted average LMP: January through March, 2001 through 2023

	Load-Weighted Average LMP	Inflation Adjusted Load-Weighted Average LMP
	Jan-Mar	Jan-Mar
2001	$37.70	$34.68
2002	$23.17	$21.04
2003	$53.16	$46.94
2004	$47.75	$41.47
2005	$46.54	$39.19
2006	$52.40	$42.57
2007	$54.87	$43.51
2008	$68.00	$51.82
2009	$49.44	$37.71
2010	$47.77	$35.59
2011	$47.14	$34.41
2012	$31.51	$22.35
2013	$37.26	$25.98
2014	$94.97	$65.40
2015	$52.02	$35.80
2016	$27.94	$19.03
2017	$30.40	$20.18
2018	$47.55	$30.93
2019	$30.76	$19.66
2020	$20.12	$12.59
2021	$31.58	$19.40
2022	$54.23	$30.91
2023	$32.16	$17.30

Price Convergence

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

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

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

Where arbitrage incentives are created by systematic modeling differences, such as differences between the day-ahead and real-time modeled transmission contingencies and marginal loss calculations, virtual bids and offers cannot result in more efficient market outcomes. Such offers may result in positive profits for the virtual but cannot change the underlying reason for the price difference. The virtual transactions will continue to profit from the activity for that reason regardless of the volume of those transactions and without improving the efficiency of the energy market. This is termed false arbitrage.

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

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

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

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

Profits of Virtual Transactions

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

Table 3-46 shows, for cleared UTCs, the number of UTCs, the number of profitable UTCs, and the number of UTCs profitable at their source point, at their sink point, and at both points in the first three months of 2022 and 2023. In the first three months of 2023, 45.9 percent of all cleared UTC transactions were profitable. Of cleared UTC transactions, 72.8 percent were profitable on the source side and 27.8 percent were profitable on the sink side, but only 5.9 percent were profitable on both the source and sink side.

Table 3-46 Cleared UTCs with positive profits at source and sink points: January through March, 2022 and 2023[90]

(Jan-Mar)	Number of Cleared UTCs	Number of Profitable UTCs	Profitable at Source	Profitable at Sink	Profitable at Source and Sink	Share Profitable Overall	Share Profitable Source	Share Profitable Sink	Share Profitable Source and Sink
2022	1,167,877	594,917	854,015	350,824	123,907	50.9%	73.1%	30.0%	10.6%
2023	2,096,433	953,773	1,525,948	583,046	123,143	45.5%	72.8%	27.8%	5.9%

Table 3-47 shows the number of cleared INC and DEC transactions and the number of profitable transactions in the first three months of 2022 and 2023. Of cleared INC and DEC transactions in the first three months of 2023, 71.0 percent of INCs were profitable and 31.2 percent of DECs were profitable.

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

(Jan-Mar)	Cleared INC	Profitable INC	Profitable INC Share	Cleared DEC	Profitable DEC	Profitable DEC Share
2022	721,208	509,950	70.7%	703,749	225,714	32.1%
2023	831,855	590,295	71.0%	636,850	198,540	31.2%

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

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

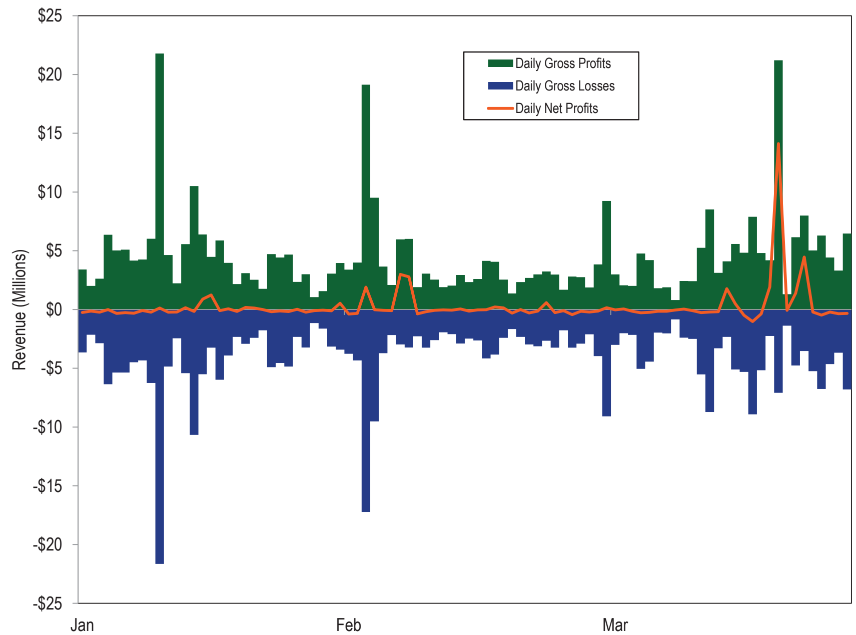


Figure 3-36 shows the cumulative UTC daily total net profits for each year from 2013 through the first three months of 2023.[91] Administrative charges are included for all dates, and uplift charges are included starting from November 1, 2020, when these charges were first applied to UTCs. Total UTC profits were higher in 2022 than any year since 2014. In the first three months of 2023, the most profitable UTC transactions were concentrated in the Dominion Zone and on dates with high real-time congestion in the Dominion Zone.

90 Calculations exclude PJM administrative charges.

91 UTCs paid uplift only after October 31, 2020.

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

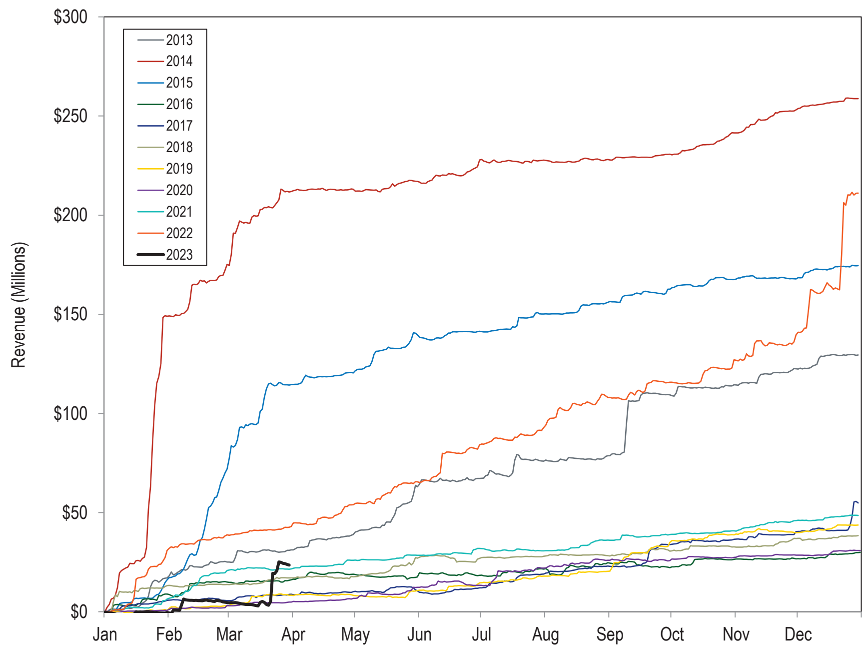


Table 3-48 shows UTC profits by month for January 2013 through March 2023. The totals include administrative charges for all months and uplift charges beginning in November 2020, when UTCs first became subject to uplift charges. UTC profits were $211 million in 2022, higher than any year since 2014, with the largest monthly totals in December at $75 million and January at $31 million.

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

	January	February	March	April	May	June	July	August	September	October	November	December	Total
2013	$17,048,654	$8,304,767	$5,629,392	$7,560,773	$25,219,947	$3,484,372	$8,781,526	$2,327,168	$31,160,618	$4,393,583	$8,730,701	$6,793,990	$129,435,490
2014	$148,973,434	$23,235,621	$39,448,716	$1,581,786	$3,851,636	$7,353,460	$3,179,356	$287,824	$2,727,763	$10,889,817	$11,042,443	$6,191,101	$258,762,955
2015	$16,132,319	$53,830,098	$44,309,656	$6,392,939	$19,793,475	$824,817	$8,879,275	$5,507,608	$6,957,012	$4,852,454	$392,876	$6,620,581	$174,493,110
2016	$8,874,363	$6,118,477	$1,119,457	$2,768,591	($1,333,563)	$841,706	$3,128,346	$3,200,573	($2,518,408)	$4,216,717	$254,684	$3,271,368	$29,942,312
2017	$5,716,757	($17,860)	$3,083,167	$944,939	$1,245,988	$868,400	$7,053,390	$4,002,063	$10,960,012	$2,360,817	$2,716,950	$15,936,217	$54,870,839
2018	$13,184,346	$506,509	$3,410,577	$688,796	$9,499,735	($768,614)	$1,163,380	$692,736	$2,845,649	$1,452,515	$4,339,363	$1,358,446	$38,373,436
2019	$574,901	$2,407,307	$5,287,985	$332,036	$1,833,879	$3,382,009	$4,066,461	$2,442,971	$12,599,278	$5,914,042	$1,171,145	$3,722,403	$43,734,418
2020	$664,972	$2,497,856	$1,720,037	$1,865,139	$5,508,276	$1,123,429	$8,573,276	$3,957,296	($141,240)	$1,628,186	$1,170,367	$2,319,727	$30,887,320
2021	$6,421,567	$13,241,294	$1,788,961	$4,529,921	$2,542,898	$3,384,291	($1,199,849)	$5,330,600	$2,649,331	$2,148,861	$5,091,590	$2,665,873	$48,595,339
2022	$30,954,077	$7,236,325	$4,411,627	$11,317,095	$11,658,586	$16,398,181	$9,481,970	$17,376,381	$6,783,480	$7,325,933	$13,116,641	$75,067,601	$211,127,897
2023	($374,877)	$5,180,921	$18,722,180										$23,528,224

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

Figure 3-37 Daily gross profits, gross losses, and net profits of all INC and DEC transactions: January through March, 2023[92]

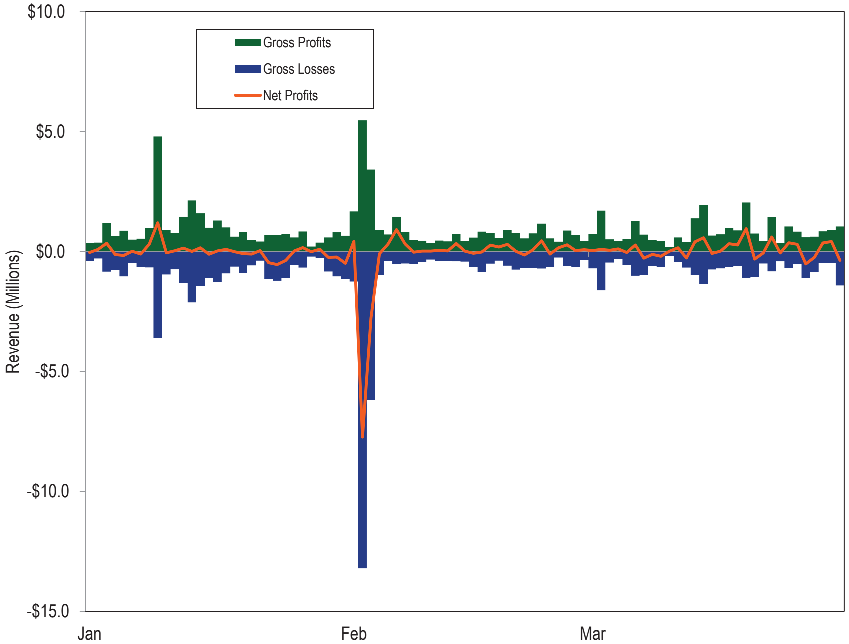
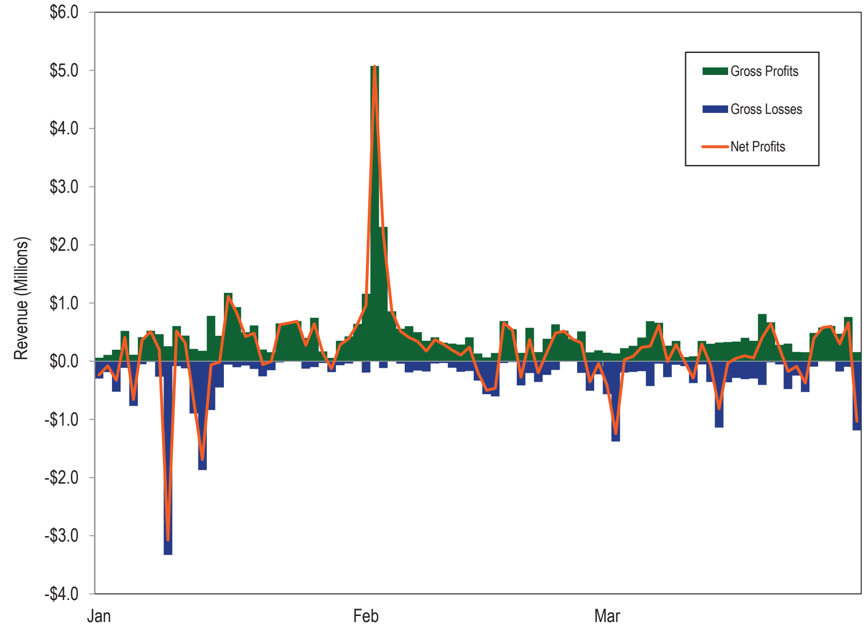


Figure 3-38 shows the positive, negative, and net daily profits for INCs in the first three months of 2023.

Figure 3-38 Daily gross profits, gross losses, and net profits for INC transactions: January through March, 2023[93]



92 Calculations exclude PJM administrative charges.

93 Calculations exclude PJM administrative charges.

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

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

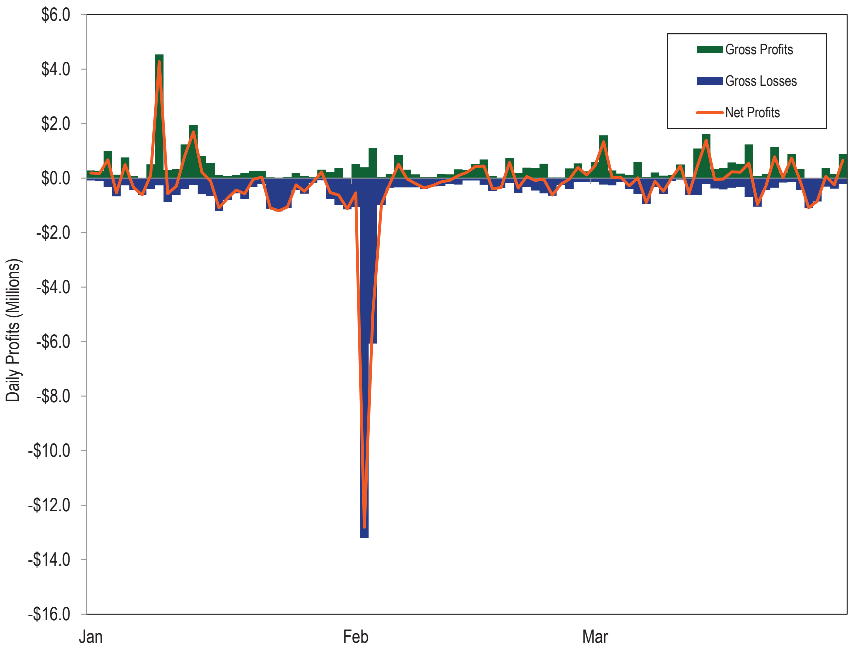


Figure 3-40 shows the cumulative INC and DEC daily profits in the first three months of 2023. Virtual trading can be profitable without contributing to price convergence because the addition of virtual supply or demand in the day-ahead market does not and cannot correct for factors not included in the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

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

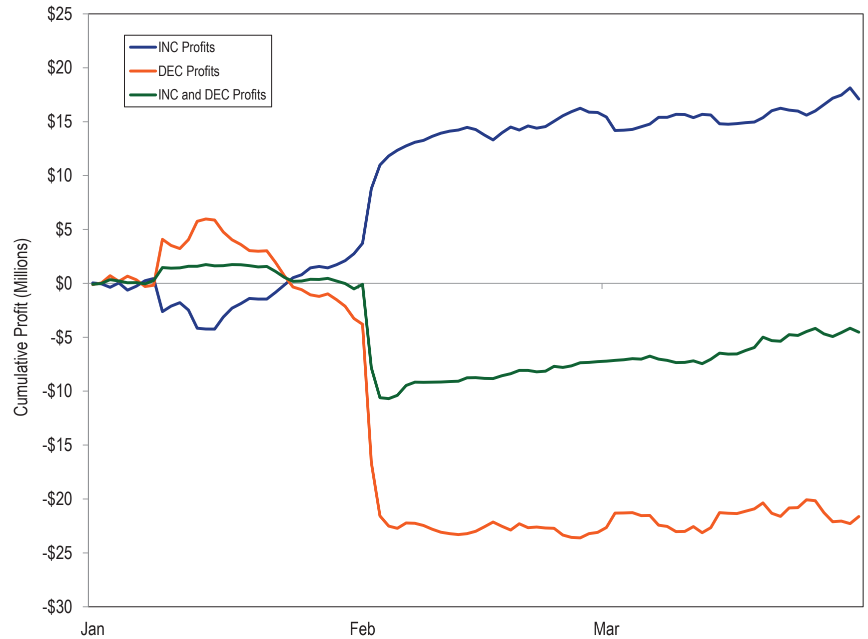


Table 3-49 shows INC and DEC profits by month in the first three months of 2023.

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

Month	INCs	DECs	INCs and DECs
January	$2,113,265	($2,128,961)	($15,696)
February	$13,770,344	($21,087,236)	($7,316,892)
March	$1,217,514	$1,588,437	$2,805,951
Total	$17,101,123	($21,627,760)	($4,526,637)

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

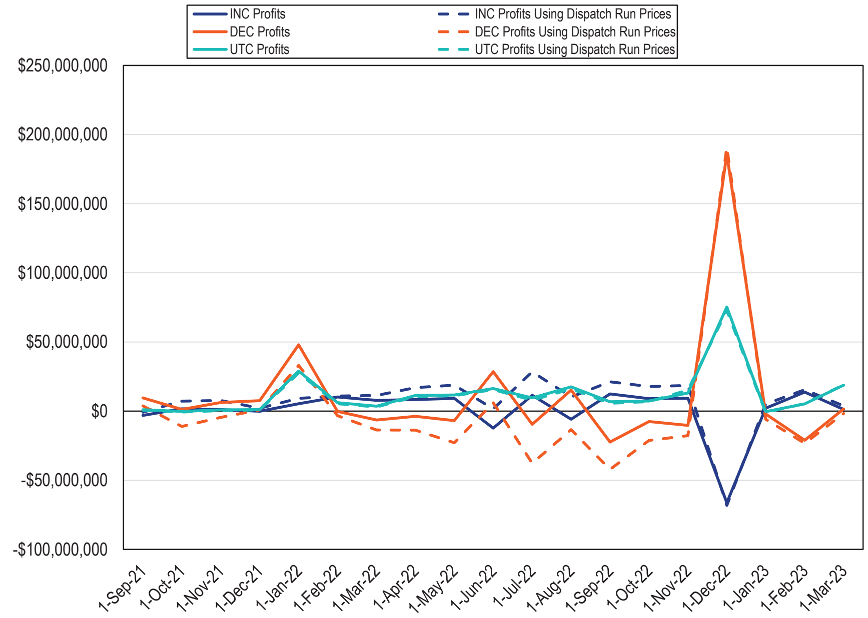
In the first three months of 2023, INCs paid a total of $0.8 million, DECs paid a total of $1.0 million, and UTCs paid a total of $4.7 million in uplift. The uplift charges were 4.4 percent of total INC profits of $17.1 million, 4.4 percent of total DEC losses of $21.6 million, and 20.1 percent of total UTC profits of $23.5 million.

Effect of Fast Start Pricing on Virtuals

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

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

Figure 3-41 Monthly profits for virtuals using pricing run versus dispatch run prices: September 1, 2021 through March 31, 2023



From the implementation of fast start pricing on September 1, 2021, through March 31, 2023, the cumulative difference in profit between the pricing run and the dispatch run for INCs was -$122.3 million, the cumulative difference in profit for DECs was $210.9 million, and the cumulative difference in profit for UTCs was $11.4 million, a net total of $100.0 million.

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

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

Day-ahead and Real-time Prices

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

Table 3-50 Day-ahead and real-time average LMP (Dollars per MWh): January through March, 2022 and 2023[94]

	2022 (Jan-Mar)				2023 (Jan-Mar)			
	Day-Ahead	Real-Time	Difference	Percent of Real Time	Day-Ahead	Real-Time	Difference	Percent of Real Time
Average	$52.25	$51.95	($0.30)	(0.6%)	$31.26	$29.57	($1.68)	(5.7%)
Median	$46.67	$43.28	($3.39)	(7.8%)	$29.08	$26.50	($2.58)	(9.7%)
Standard deviation	$19.40	$36.57	$17.17	47.0%	$12.18	$18.55	$6.37	34.3%
Peak average	$54.26	$51.10	($3.16)	(6.2%)	$33.88	$31.93	($1.95)	(6.1%)
Peak median	$48.85	$44.78	($4.07)	(9.1%)	$31.68	$29.36	($2.33)	(7.9%)
Peak standard deviation	$18.29	$24.57	$6.28	25.6%	$13.33	$22.80	$9.48	41.6%
Off peak average	$50.44	$52.72	$2.28	4.3%	$28.89	$27.45	($1.44)	(5.2%)
Off peak median	$43.98	$41.24	($2.74)	(6.6%)	$26.76	$23.97	($2.79)	(11.6%)
Off peak standard deviation	$20.19	$44.72	$24.53	54.9%	$10.50	$13.27	$2.77	20.9%

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

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

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

	Load-Weighted Average LMP			
Jan-Mar	Day-Ahead	Real-Time	Difference	Percent of Real-Time
2001	$37.70	$35.16	($2.54)	(7.2%)
2002	$23.17	$23.01	($0.15)	(0.7%)
2003	$53.16	$51.93	($1.23)	(2.4%)
2004	$47.75	$48.77	$1.02	2.1%
2005	$46.54	$48.37	$1.84	3.8%
2006	$52.40	$54.43	$2.03	3.7%
2007	$54.87	$58.07	$3.20	5.5%
2008	$68.00	$69.35	$1.35	2.0%
2009	$49.44	$49.60	$0.16	0.3%
2010	$47.77	$45.92	($1.85)	(4.0%)
2011	$47.14	$46.35	($0.79)	(1.7%)
2012	$31.51	$31.21	($0.30)	(1.0%)
2013	$37.26	$37.41	$0.15	0.4%
2014	$94.97	$92.98	($1.99)	(2.1%)
2015	$52.02	$50.91	($1.11)	(2.2%)
2016	$27.94	$26.80	($1.14)	(4.3%)
2017	$30.40	$30.28	($0.12)	(0.4%)
2018	$47.55	$49.45	$1.89	3.8%
2019	$30.76	$30.16	($0.60)	(2.0%)
2020	$20.12	$19.85	($0.27)	(1.3%)
2021	$31.58	$30.84	($0.74)	(2.4%)
2022	$54.23	$54.13	($0.10)	(0.2%)
2023	$32.16	$30.28	($1.88)	(6.2%)

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

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

	2022 Jan - Mar		2023 Jan - Mar	
LMP	Frequency	Cumulative Percent	Frequency	Cumulative Percent
< ($200)	0	0.0%	0	0.0%
($200) to ($100)	0	0.0%	2	0.1%
($100) to ($50)	3	0.1%	14	0.7%
($50) to $0	1,580	73.3%	1,568	73.4%
$0 to $50	520	97.4%	561	99.4%
$50 to $100	26	98.6%	13	100.0%
$100 to $200	20	99.5%	0	100.0%
$200 to $400	7	99.9%	0	100.0%
$400 to $800	3	100.0%	1	100.0%
>= $800	0	100.0%	0	100.0%

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

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

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

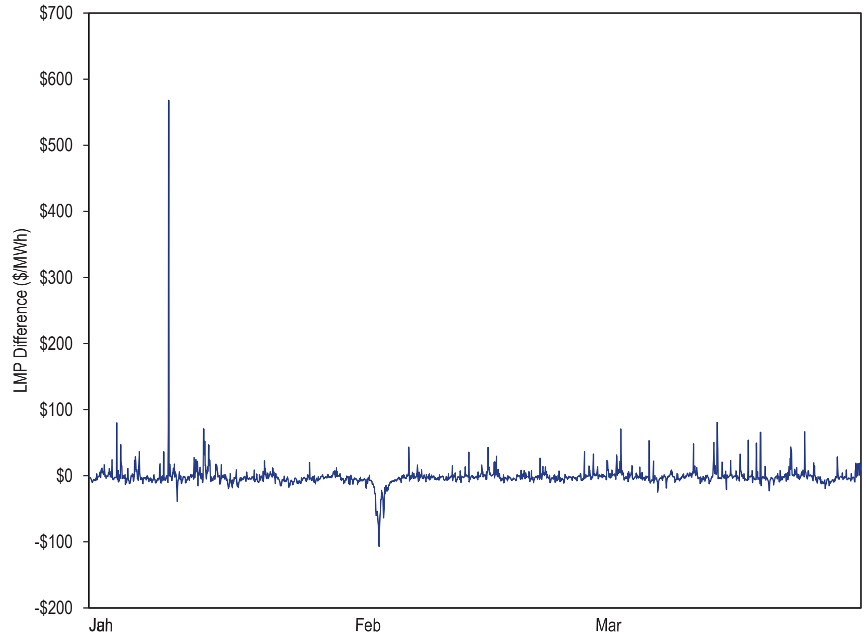
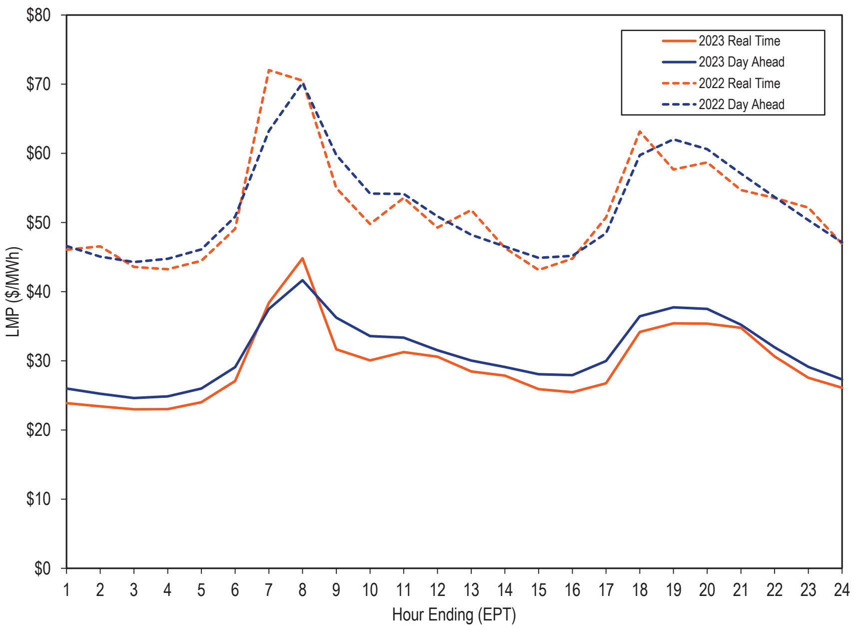


Figure 3-43 shows day-ahead and real-time load-weighted average LMP by hour of the day for the first three months of 2022 and 2023.

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



Zonal LMP and Dispatch

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

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

	Real-Time Average LMP			Real-Time Load-Weighted Average LMP		
Zone	2022 Jan-Mar	2023 Jan-Mar	Percent Change	2022 Jan-Mar	2023 Jan-Mar	Percent Change
ACEC	$54.67	$26.53	(51.5%)	$58.69	$27.46	(53.2%)
AEP	$47.57	$29.89	(37.2%)	$48.84	$30.58	(37.4%)
APS	$50.91	$30.47	(40.2%)	$53.11	$31.37	(40.9%)
ATSI	$46.55	$29.80	(36.0%)	$47.33	$30.29	(36.0%)
BGE	$59.53	$32.51	(45.4%)	$64.33	$33.79	(47.5%)
COMED	$38.21	$26.35	(31.0%)	$38.89	$26.82	(31.0%)
DAY	$48.52	$31.15	(35.8%)	$49.56	$31.83	(35.8%)
DUKE	$47.09	$30.42	(35.4%)	$48.12	$31.12	(35.3%)
DOM	$59.77	$33.20	(44.5%)	$64.54	$34.21	(47.0%)
DPL	$62.65	$28.47	(54.6%)	$69.86	$30.07	(57.0%)
DUQ	$44.83	$29.44	(34.3%)	$45.66	$29.95	(34.4%)
EKPC	$47.72	$30.19	(36.7%)	$49.80	$31.30	(37.1%)
JCPLC	$56.64	$26.86	(52.6%)	$60.51	$27.65	(54.3%)
MEC	$57.38	$29.00	(49.5%)	$60.83	$29.77	(51.1%)
OVEC	$45.84	$29.75	(35.1%)	$46.22	$29.99	(35.1%)
PECO	$54.58	$25.60	(53.1%)	$58.38	$26.19	(55.1%)
PE	$52.49	$29.34	(44.1%)	$54.05	$29.92	(44.6%)
PEPCO	$59.35	$31.74	(46.5%)	$64.19	$33.01	(48.6%)
PPL	$52.15	$27.01	(48.2%)	$55.23	$27.64	(49.9%)
PSEG	$61.07	$27.10	(55.6%)	$64.47	$27.70	(57.0%)
REC	$65.23	$28.48	(56.3%)	$68.72	$29.21	(57.5%)
PJM	$51.95	$29.57	(43.1%)	$54.13	$30.28	(44.1%)

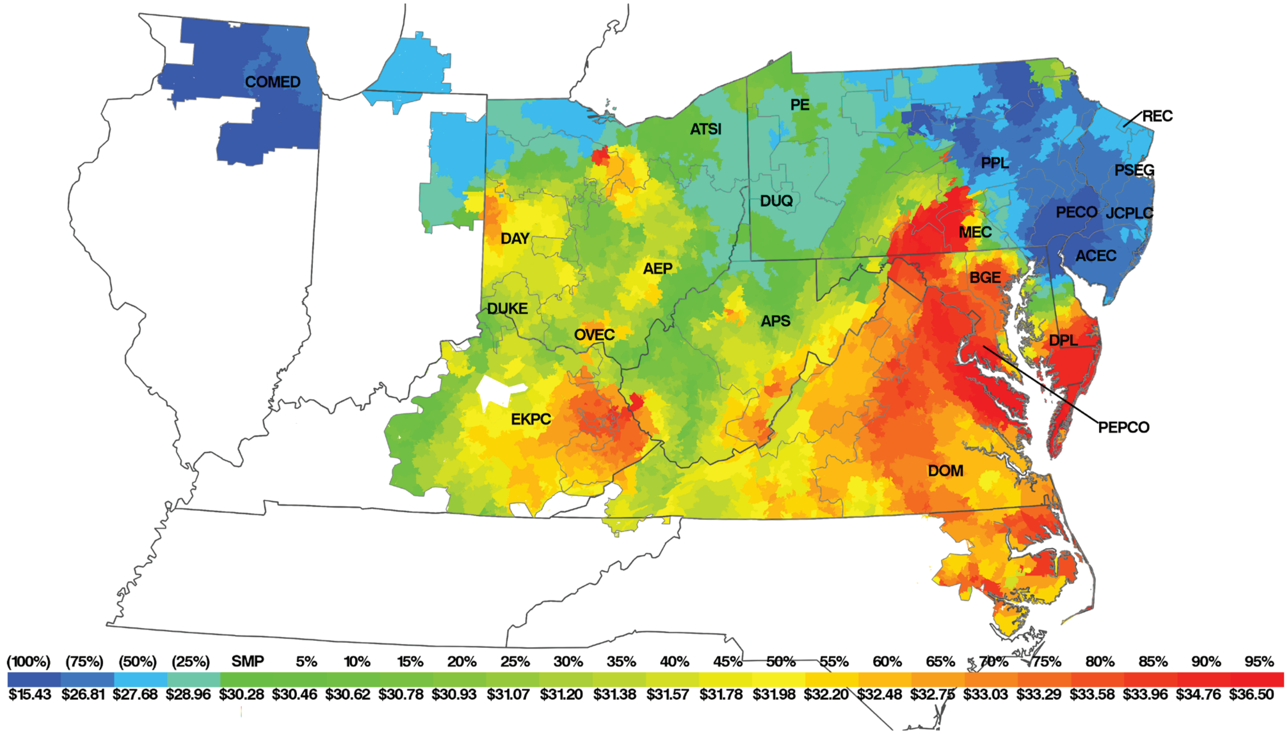
Table 3-54 shows day-ahead zonal average and load-weighted average LMP for the first three months of 2022 and 2023.

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

	Day-Ahead Average LMP			Day-Ahead Load-Weighted Average LMP		
	2022	2023	Percent	2022	2023	Percent
Zone	Jan-Mar	Jan-Mar	Change	Jan-Mar	Jan-Mar	Change
ACEC	$51.52	$28.18	(45.3%)	$54.34	$29.24	(46.2%)
AEP	$49.47	$31.45	(36.4%)	$50.91	$32.12	(36.9%)
APS	$52.24	$32.60	(37.6%)	$54.42	$33.68	(38.1%)
ATSI	$49.01	$31.59	(35.5%)	$49.92	$32.11	(35.7%)
BGE	$59.70	$36.52	(38.8%)	$63.15	$38.41	(39.2%)
COMED	$40.34	$26.81	(33.5%)	$41.12	$27.24	(33.8%)
DAY	$50.72	$32.81	(35.3%)	$52.02	$33.57	(35.5%)
DUKE	$49.62	$32.02	(35.5%)	$50.89	$32.76	(35.6%)
DOM	$58.98	$34.69	(41.2%)	$62.77	$36.06	(42.6%)
DPL	$57.36	$29.17	(49.1%)	$63.12	$31.37	(50.3%)
DUQ	$47.26	$30.91	(34.6%)	$48.19	$31.46	(34.7%)
EKPC	$50.06	$31.55	(37.0%)	$52.57	$32.83	(37.6%)
JCPLC	$53.38	$28.61	(46.4%)	$55.98	$29.76	(46.8%)
MEC	$57.81	$31.32	(45.8%)	$60.95	$32.64	(46.5%)
OVEC	$48.18	$31.07	(35.5%)	$46.04	$27.70	(39.8%)
PECO	$51.48	$27.05	(47.5%)	$54.10	$27.99	(48.3%)
PE	$55.01	$31.90	(42.0%)	$57.50	$33.48	(41.8%)
PEPCO	$58.79	$35.51	(39.6%)	$62.74	$37.55	(40.1%)
PPL	$52.99	$29.04	(45.2%)	$55.49	$29.99	(46.0%)
PSEG	$56.50	$29.23	(48.3%)	$59.02	$30.50	(48.3%)
REC	$60.27	$31.09	(48.4%)	$65.92	$34.46	(47.7%)
PJM	$52.25	$31.26	(40.2%)	$54.23	$32.16	(40.7%)

Figure 3-44 is a map of the real-time load-weighted average LMP for the first three months of 2023. In the legend, green represents the system marginal price (SMP) and each increment to the right and left of the SMP represents five percent of the pricing nodes above and below the SMP.

Figure 3-44 Real-time load-weighted average LMP: January through March, 2023



Transmission Constraint Penalty Factors

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

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

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

Table 3-55 shows the frequency and average shadow price of transmission constraints in PJM real-time market. In the first three months of 2023, there were 30,719 transmission constraint intervals in the real-time market with a nonzero shadow price. For about six percent of these transmission constraint intervals, the line limit was violated, meaning that the flow exceeded the facility limit used in SCED.[95] For 39 percent of those violations, PJM had reduced the line rating. In those cases, the actual line limit was not violated. In the first three months of 2023, the average shadow price of transmission constraints when the line limit used in SCED was violated was 6.3 times higher than when the transmission constraint was binding at its limit used in SCED.

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

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

	Frequency (Constraint Intervals)		Average Shadow Price	
Description	2022 (Jan - Mar)	2023 (Jan - Mar)	2022 (Jan - Mar)	2023 (Jan - Mar)
Violated Transmission Constraints	5,685	1,769	$1,468.87	$962.19
Binding Transmission Constraints	28,365	15,917	$257.23	$153.59
Market to Market Transmission Constraints	25,302	13,033	$378.20	$180.19
All Transmission Constraints	59,352	30,719	$424.86	$211.44

Table 3-56 shows the frequency and average shadow price of transmission constraints in the PJM day-ahead market. In the first three months of 2023, there were 21,091 transmission constraint hours in the day-ahead market with a nonzero shadow price. For less than one percent of these transmission constraint hours, the line limit was violated, meaning that the flow exceeded the facility limit used in the DA pricing run solution.

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

	Frequency (Constraint Intervals)		Average Shadow Price	
Description	2022 (Jan - Mar)	2023 (Jan - Mar)	2022 (Jan - Mar)	2023 (Jan - Mar)
Violated Transmission Constraints	1	6	$2,000.00	$2,000.00
Binding Transmission Constraints	17,144	16,322	$79.62	$30.79
Market to Market Transmission Constraints	3,946	2,278	$177.96	$109.70
All Transmission Constraints	21,091	18,606	$98.11	$41.09

Table 3-57 shows the frequency of violated transmission constraints by voltage level. In the first three months of 2023, 97.7 percent of the violated transmission constraint intervals had a voltage level at or below 230 kV.

95 The line limit of a facility associated with a transmission constraint is not necessarily the rated line limit. In PJM, the dispatcher has the discretion to lower the rated line limit.

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

	2022 (Jan-Mar)		2023 (Jan-Mar)	
Voltage	Frequency (Constraint Intervals)	Percent	Frequency (Constraint Intervals)	Percent
1 kV	21	0.4%	-	0.0%
69 kV	7	0.1%	40	2.3%
115 kV	3,452	60.7%	533	30.1%
138 kV	642	11.3%	261	14.8%
230 kV	1,221	21.5%	894	50.5%
345 kV	26	0.5%	40	2.3%
500 kV	316	5.6%	1	0.1%
Total	5,685	100.0%	1,769	100.0%

Transmission penalty factors should be applied without discretion, but not without additional rules that prevent unintended consequences. PJM adopted the MMU's recommendation to remove the constraint relaxation logic and allow transmission penalty factors to set prices in the day-ahead and real-time markets for all internal transmission constraints. But the potential for prolonged and excessively high administrative pricing in the energy market due to transmission constraint penalty factors remains an issue that needs to be addressed. There can be situations in which the application of transmission penalty factors in real time for significant periods creates manipulation opportunities for virtuals and creates inefficient wealth transfers when market participants do not have the ability to react to the high prices either on the supply or demand side.[96] This could be the result of a lengthy planned transmission outage, for example.[97] It can also result from PJM reducing the line limit in RT SCED below 100 percent of the actual line limit and triggering the transmission constraint penalty factor, while operating the system below the actual line limit for a prolonged period. PJM should not reduce transmission line limits in SCED to trigger the inclusion of transmission constraint penalty factors in price.

PJM also revised the tariff to list the conditions under which transmission penalty factors would be changed from their default value of $2,000 per MWh. The new rules went into effect on February 1, 2019. The Commission approved the PJM and MISO joint filing to remove the constraint relaxation logic for market to market constraints on March 6, 2020. PJM and MISO implemented the changes to their dispatch software in the second half of 2020. On March 21, 2023, FERC approved new rules proposed by PJM to allow for changes to the transmission penalty factors for constraints that are violated due to a transmission outage for which limited generation resources are available to provide relief.[98]

PJM routinely, based on discretion, reduces the line limit modeled in SCED to below 100 percent, generally to 95 percent of the actual limit, in order to trigger the use of transmission constraint penalty factors. Table 3-58 shows the frequency of changes to the transmission constraints for binding and violated transmission constraints in the PJM real-time market. In the first three months of 2023, there were 686 or 39 percent of 1,769 violated transmission constraint intervals in the real-time market with a constraint limit less than 100 percent of the actual constraint limit. In the first three months of 2023, among the constraints with reduced constraint limits, the constraint limit was reduced on average by 5.3 percent.

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

	Frequency (Constraint Intervals)		Constraints with Reduced Line Limits (Constraint Intervals)		Average Reduction (Percentage)	
Description	2022 (Jan - Mar)	2023 (Jan - Mar)	2022 (Jan - Mar)	2023 (Jan - Mar)	2022 (Jan - Mar)	2023 (Jan - Mar)
Violated Transmission Constraints	5,685	1,769	3,896	686	6.2%	5.3%
Binding Transmission Constraints	28,365	15,917	25,692	15,190	6.3%	5.8%
Market to Market Transmission Constraints	25,302	13,033	8,687	2,845	5.6%	5.2%
All Transmission Constraints	59,352	30,719	38,275	18,721	6.1%	5.7%

Table 3-59 shows the reasons provided by the PJM dispatchers for changing the line rating for violated transmission constraints. In the first three months of 2023, of the 686 violated transmission constraints with reduced line ratings, 10 or 1.5 percent were reduced because the relief calculated by the SCED optimization was less than the dispatcher's desired relief for the transmission

96 See Comments of the Independent Market Monitor for PJM, Docket No. EL22-26-000 et al. (February 1, 2022); 178 FERC ¶ 61,104 (2022).
97 See *id.*
98 See 182 FERC ¶ 61,183 (March 21, 2023).

constraint. No reason was provided for 554 instances, or 81 percent of all the instances. The MMU recommends that PJM end the practice of discretionary reductions in transmission line ratings modeled in SCED. This practice has significant market impacts by increasing prices above the level that would exist if the actual line rating were enforced.

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

	Constraint Intervals		Average Reduction (Percentage)	
Reason	2022 (Jan - Mar)	2023 (Jan - Mar)	2022 (Jan - Mar)	2023 (Jan - Mar)
Modeled constraint is a thermal surrogate	18	-	70.4%	0.0%
No reason provided	2,193	554	4.5%	4.6%
Prepositioning of generation resources to support an operational requirement	83	29	10.1%	11.2%
Inadequate relief calculated by the SCED optimization	1,076	10	7.5%	7.4%
Transmission owner identified the flow on their constraint to be greater than PJM's calculated flow on the same constraint.	232	49	8.9%	8.3%
Power flow on the constraint is volatile due to various system conditions	294	44	7.3%	7.0%
Total	3,896	686	6.2%	5.3%

Table 3-60 shows the impact on LMP of PJM dispatchers reducing the line ratings of transmission constraints and causing artificial line limit violations.[99] The transmission penalty factor contribution to the load weighted average LMP in the first three months of 2023 was $0.75 per MWh. If 100 percent of the line limits had been used for the PJM transmission constraints and everything else remained unchanged, fewer constraints would have been violated and the transmission penalty factor's contribution to the load weighted average LMP would have decreased to $0.01 per MWh or 99.1 percent lower.

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

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

	Contribution to LMP	
Line Limit Scenario for Violated Constraints	2022 (Jan - Mar)	2023 (Jan - Mar)
Line Limits Reduced by PJM (Actual)	$4.40	$0.75
Hypothetical Use of Full Line Limits	($0.03)	$0.01
Change in Contribution to LMP	($4.43)	($0.74)
Percent Change in Contribution to LMP	(100.8%)	(99.1%)

Table 3-61 shows the frequency of changes to the magnitude of transmission penalty factors for binding and violated transmission constraints in the PJM Real-Time Energy Market. In the first three months of 2023, there were 773 or 44 percent of violated transmission constraint intervals in the real-time market with a transmission penalty factor equal to the default $2,000 per MWh. Of the 996 constraint intervals violated with a penalty factor reduced below the default of $2,000 per MWh, the Harwood Transformer contingency constraint accounted for nearly 71 percent in the first three months of 2023.

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

	2022 (Jan - Mar)			2023 (Jan - Mar)		
Description	$2,000 per MWh (Default)	Above $2,000 per MWh	Below $2,000 per MWh	$2,000 per MWh (Default)	Above $2,000 per MWh	Below $2,000 per MWh
Violated Transmission Constraints	3,769	-	1,916	773	-	996
Binding Transmission Constraints	27,745	-	620	15,339	-	578
Market to Market Transmission Constraints	3,506	-	21,796	368	-	12,665
All Transmission Constraints	35,020	-	24,332	16,480	-	14,239

Prior to June 1, 2022, transmission constraint penalty factors frequently set prices when PJM modeled a surrogate constraint to limit the dispatch of a generator that would experience voltage instability at its full output due to a transmission outage. Since June 1, 2022, PJM is using a generator output limit constraint to manage generator voltage instability issues. In the first three months of 2023, there were 361 five minute intervals during which PJM reduced the output of generators to manage instability. Changes to the surrogate constraint limit that exceed the unit's ability to reduce output cause constraint violations. Constraint violations also occur when the unit follows the regulation signal or increases its minimum operating parameters above the surrogate constraint limit. Prices set at the $2,000 per MWh penalty factor are not useful signals to the market under these conditions and create false arbitrage opportunities for virtuals.

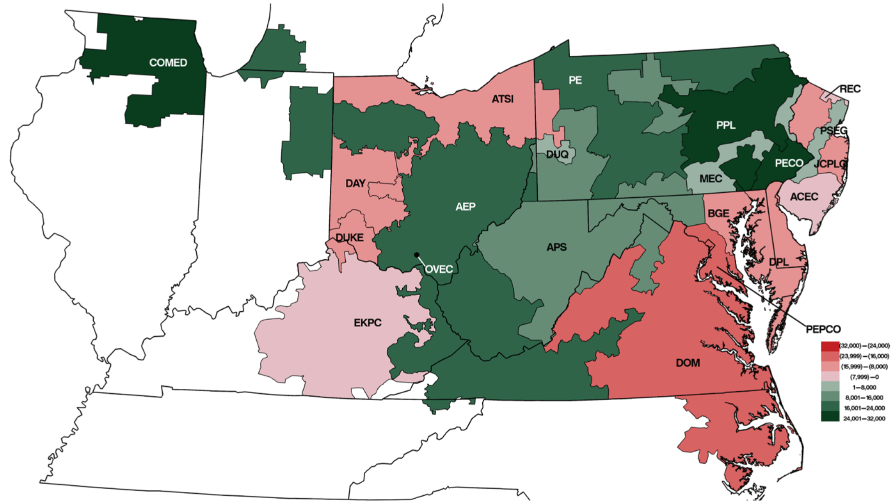
PJM used CT pricing logic until the implementation of fast start pricing on September 1, 2021, to force otherwise uneconomic resources to be marginal and set price in the day-ahead and real-time market solutions. In the event PJM committed a resource that is uneconomic and/or offered with inflexible parameters, PJM used CT pricing logic to model a constraint with a variable flow limit, paired with an artificial override of the inflexible resource's economic minimum, to force the resource to be marginal in the PJM market solution.[100] Frequently, PJM dispatchers also manually overrode the transmission violation penalty factor of the constraint to match the offer price of the resource to artificially control the shadow price of the constraint.

PJM's use of CT pricing logic was inconsistent with the efficient market dispatch and pricing. For that reason, in 2019 FERC declared CT pricing logic to be unjust and unreasonable.[101] PJM continues to use similar methods to artificially change the prices, like using thermal surrogates and forcing units to be marginal. These practices can lead to inefficient market outcomes.

Net Generation by Zone

Figure 3-45 shows the difference between the PJM real-time generation and real-time load by zone for the first three months of 2023. Figure 3-45 is color coded using a scale on which red shades represent zones that have less generation than load and green shades represent zones that have more generation than load, with darker shades meaning greater amounts of net generation or load. Table 3-62 shows the difference between the real-time generation and real-time load by zone for the first three months of 2022 and 2023.

Figure 3-45 Map of real-time generation less real-time load by zone: January through March, 2023[102]



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

101 167 FERC ¶ 61,058 at P 69 (2019).

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

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

	Zonal Generation and Load (GWh)					
	2022 (Jan-Mar)			2023 (Jan-Mar)		
Zone	Generation	Load	Net	Generation	Load	Net
ACEC	572	2,249	(1,677)	489	2,129	(1,640)
AEP	37,796	32,895	4,900	38,010	31,226	6,784
APS	14,908	13,179	1,730	13,624	12,303	1,321
ATSI	14,525	16,635	(2,110)	12,626	16,119	(3,493)
BGE	4,027	7,893	(3,866)	3,537	7,210	(3,672)
COMED	34,202	22,981	11,221	32,890	21,945	10,945
DAY	270	4,388	(4,117)	205	4,151	(3,945)
DUKE	5,305	6,592	(1,287)	2,367	6,152	(3,785)
DOM	22,979	28,004	(5,025)	23,465	27,490	(4,024)
DPL	844	4,868	(4,024)	878	4,399	(3,520)
DUQ	4,790	3,193	1,597	4,277	3,127	1,150
EKPC	2,483	3,674	(1,191)	1,777	3,423	(1,646)
JCPLC	1,157	5,231	(4,074)	1,514	4,934	(3,419)
MEC	4,968	4,063	905	5,308	3,800	1,508
OVEC	2,833	32	2,801	2,255	34	2,221
PECO	17,722	9,684	8,038	19,745	9,034	10,711
PE	11,723	4,458	7,265	7,978	4,235	3,743
PEPCO	2,285	7,083	(4,797)	2,196	6,542	(4,346)
PPL	18,999	11,073	7,926	17,269	10,306	6,964
PSEG	10,285	10,149	136	10,235	9,644	591
REC	0	319	(319)	0	304	(304)

Net Generation and Load

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

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

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

Fuel Prices, LMP, and Dispatch

Energy Production by Fuel Source

Table 3-63 shows PJM generation by fuel source in GWh for the first three months of 2022 and 2023. In the first three months of 2023, generation from coal units decreased 40.1 percent, generation from natural gas units increased 12.5 percent, and generation from oil decreased 11.9 percent compared to the first three months of 2022. Wind and solar output rose by 3.6 percent compared to the first three months of 2022, supplying 5.8 percent of PJM energy in the first three months of 2023.

Table 3-63 Generation (By fuel source (GWh)): January through March, 2022 and 2023[103] [104]

	2022 (Jan-Mar)		2023 (Jan-Mar)		
	GWh	Percent	GWh	Percent	Change in Output
Coal	50,954.3	23.7%	30,523.8	15.0%	(40.1%)
Bituminous	44,664.6	20.7%	27,806.7	13.7%	(37.7%)
Sub Bituminous	4,647.6	2.2%	1,332.0	0.7%	(71.3%)
Other Coal	1,642.1	0.8%	1,385.1	0.7%	(15.7%)
Nuclear	69,238.6	32.1%	67,873.9	33.4%	(2.0%)
Gas	77,514.5	36.0%	87,080.3	42.8%	12.3%
Natural Gas CC	73,195.5	34.0%	83,656.0	41.1%	14.3%
Natural Gas CT	2,956.8	1.4%	2,071.5	1.0%	(29.9%)
Natural Gas Other Units	986.0	0.5%	1,020.8	0.5%	3.5%
Other Gas	376.2	0.2%	332.0	0.2%	(11.7%)
Hydroelectric	4,250.5	2.0%	4,086.3	2.0%	(3.9%)
Pumped Storage	1,244.7	0.6%	1,212.8	0.6%	(2.6%)
Run of River	2,647.2	1.2%	2,531.0	1.2%	(4.4%)
Other Hydro	358.6	0.2%	342.5	0.2%	(4.5%)
Wind	9,715.6	4.5%	9,928.7	4.9%	2.2%
Waste	939.9	0.4%	977.8	0.5%	4.0%
Oil	689.9	0.3%	607.9	0.3%	(11.9%)
Heavy Oil	7.5	0.0%	1.8	0.0%	(76.5%)
Light Oil	173.8	0.1%	194.4	0.1%	11.9%
Diesel	35.9	0.0%	5.0	0.0%	(86.2%)
Other Oil	472.7	0.2%	406.8	0.2%	(13.9%)
Solar	1,746.2	0.8%	1,944.3	1.0%	11.3%
Battery	5.8	0.0%	6.0	0.0%	3.2%
Biofuel	359.9	0.2%	297.5	0.1%	(17.3%)
Total	215,415.1	100.0%	203,326.4	100.0%	(5.6%)

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

	Jan	Feb	Mar	Total
Coal	10,947.5	9,266.3	10,310.0	30,523.8
Bituminous	9,875.7	8,286.1	9,644.8	27,806.7
Sub Bituminous	688.1	473.8	170.0	1,332.0
Other Coal	383.7	506.3	495.1	1,385.1
Nuclear	24,467.1	21,439.6	21,967.3	67,873.9
Gas	30,707.9	27,356.8	29,015.6	87,080.3
Natural Gas CC	29,603.8	26,238.2	27,814.0	83,656.0
Natural Gas CT	698.5	648.1	724.9	2,071.5
Natural Gas Other Units	291.2	367.5	362.1	1,020.8
Other Gas	114.4	103.0	114.6	332.0
Hydroelectric	1,584.3	1,169.6	1,332.5	4,086.3
Pumped Storage	441.7	390.4	380.7	1,212.8
Run of River	1,011.3	670.9	848.8	2,531.0
Other Hydro	131.3	108.2	103.0	342.5
Wind	2,913.7	3,440.9	3,574.0	9,928.7
Waste	322.8	305.2	349.8	977.8
Oil	181.4	191.1	235.5	607.9
Heavy Oil	0.0	1.8	0.0	1.8
Light Oil	37.9	54.1	102.4	194.4
Diesel	0.1	4.1	0.7	5.0
Other Oil	143.4	131.1	132.4	406.8
Solar	417.8	598.4	928.1	1,944.3
Battery	2.3	1.7	1.9	6.0
Biofuel	119.6	86.1	91.8	297.5
Total	71,664.4	63,855.6	67,806.4	203,326.4

103 All generation is total gross generation output and does not net out the MWh withdrawn at a generation bus to provide auxiliary/parasitic power or station power, power to synchronous condenser motors, power to run pumped hydro pumps or power to charge batteries.

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

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

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

	2023 (Jan-Mar)					
	Day-Ahead		Real-Time			Percent
	GWh	Percent	GWh	Percent	Difference	Difference
Coal	31,380.5	15.6%	30,523.8	15.0%	(856.8)	(2.7%)
Bituminous	28,669.7	14.2%	27,806.7	13.7%	(863.1)	(3.0%)
Sub Bituminous	1,416.7	0.7%	1,332.0	0.7%	(84.7)	(6.0%)
Other Coal	1,294.1	0.6%	1,385.1	0.7%	91.0	7.0%
Nuclear	68,020.0	33.7%	67,873.9	33.4%	(146.0)	(0.2%)
Gas	88,012.1	43.6%	87,080.3	42.8%	(931.8)	(1.1%)
Natural Gas CC	84,595.9	41.9%	83,656.0	41.1%	(939.9)	(1.1%)
Natural Gas CT	1,986.2	1.0%	2,071.5	1.0%	85.3	4.3%
Natural Gas Other Units	1,111.3	0.6%	1,020.8	0.5%	(90.5)	(8.1%)
Other Gas	318.7	0.2%	332.0	0.2%	13.3	4.2%
Hydroelectric	4,107.3	2.0%	4,086.3	2.0%	(21.0)	(0.5%)
Pumped Storage	1,455.5	0.7%	1,212.8	0.6%	(242.7)	(16.7%)
Run of River	2,651.8	1.3%	2,531.0	1.2%	(120.8)	(4.6%)
Other Hydro	0.0	0.0%	342.5	0.2%	342.5	NA
Wind	6,989.2	3.5%	9,928.7	4.9%	2,939.5	42.1%
Waste	948.4	0.5%	977.8	0.5%	29.4	3.1%
Oil	592.0	0.3%	607.9	0.3%	15.9	2.7%
Heavy Oil	1.0	0.0%	1.8	0.0%	0.8	82.0%
Light Oil	192.0	0.1%	194.4	0.1%	2.4	1.2%
Diesel	0.2	0.0%	5.0	0.0%	4.8	2,291.0%
Other Oil	398.8	0.2%	406.8	0.2%	8.0	2.0%
Solar	1,273.0	0.6%	1,944.3	1.0%	671.3	52.7%
Battery	0.0	0.0%	6.0	0.0%	6.0	NA
Biofuel	339.0	0.2%	297.5	0.1%	(41.5)	(12.2%)
Total	201,661.4	100.0%	203,326.4	100.0%	1,665.0	0.8%

Table 3-66 shows the share of generation by natural gas, coal, nuclear and other fuel types in the real-time energy market since 2008. Generation from natural gas was 42.7 percent, the highest level since the start of PJM markets and coal was 15.0 percent, the lowest level since the start of PJM markets.

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

Jan - Mar	Natural Gas	Coal	Nuclear	Other Fuel Type
2008	5.5%	58.1%	33.2%	3.2%
2009	8.4%	52.6%	35.3%	3.6%
2010	7.1%	53.9%	34.7%	4.4%
2011	12.1%	47.8%	35.6%	4.4%
2012	19.1%	39.9%	36.3%	4.7%
2013	15.4%	44.3%	35.5%	4.7%
2014	15.1%	48.5%	31.6%	4.8%
2015	19.2%	42.5%	32.9%	5.5%
2016	24.8%	32.0%	36.6%	6.5%
2017	24.4%	33.3%	35.8%	6.5%
2018	26.7%	31.4%	34.4%	7.5%
2019	33.0%	26.9%	33.0%	7.2%
2020	39.7%	18.0%	34.5%	7.7%
2021	34.4%	25.1%	32.7%	7.9%
2022	35.8%	23.7%	32.1%	8.4%
2023	42.7%	15.0%	33.4%	8.9%

Fuel Diversity

Figure 3-46 shows the fuel diversity index (FDI_e) for PJM energy generation.[105] The FDI_e is defined as $1-\sum_{i=1}^{N} s_i^2$, where s_i is the share of fuel type i. The minimum possible value for the FDI_e is zero, corresponding to all generation from a single fuel type. The maximum possible value for the FDI_e results when each fuel type has an equal share of total generation. For a generation fleet composed of 10 fuel types, the maximum achievable index is 0.9. The fuel type categories used in the calculation of the FDI_e are the 10 primary fuel sources in Table 3-63 with nonzero generation values. As fuel diversity has increased, seasonality in the FDI_e has decreased and the FDI_e has exhibited less volatility. Since 2012, the monthly FDI_e has been less volatile as a result of the decline in the share of coal from 51.3 percent prior to 2012 to 30.9 percent from 2012 through the first three months of 2023. A significant drop in the FDI_e occurred in the fall of 2004 as a result of the expansion of the PJM market footprint into ComEd, AEP, and Dayton Power & Light Zones and the increased shares of coal and nuclear that resulted.[106] The increasing

105 The MMU developed the FDI to provide an objective metric of fuel diversity. The FDI metric is similar to the HHI used to measure market concentration. The FDI is calculated separately for energy output and for installed capacity.

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

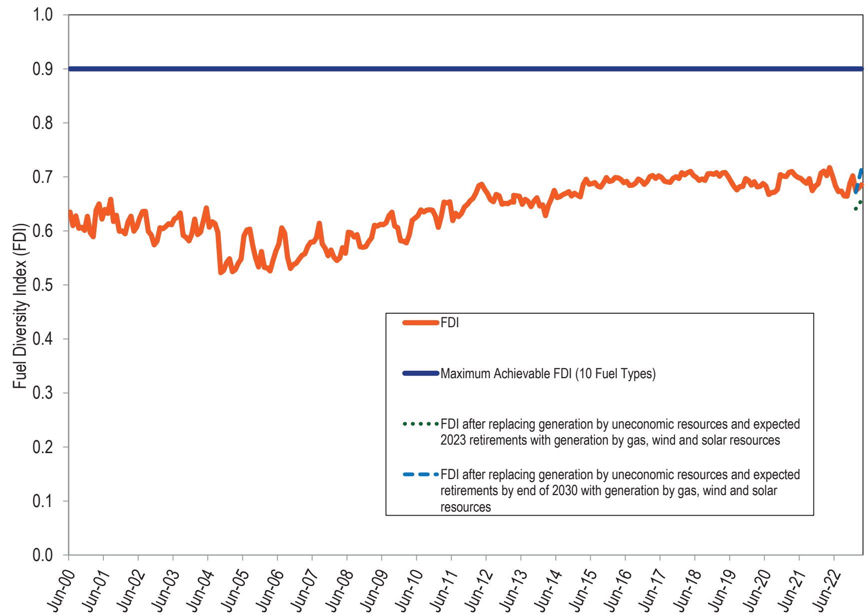
trend that began in 2008 is a result of decreasing coal generation, increasing gas generation and increasing wind generation. Coal generation as a share of total generation was 58.1 percent for the first three month of 2008 and 15.0 percent for the first three months of 2023. Gas generation as a share of total generation was 5.5 percent for the first three months of 2008 and 42.8 percent for the first three months of 2023. Wind and solar generation as a share of total generation was 0.5 percent for the first three months of 2008 and 5.8 percent for the first three months of 2023.

The FDI_e decreased 4.1 percent in the first three months of 2023 compared to the first three months of 2022.

The FDI_e was also used to measure the impact on fuel diversity of potential retirements in 2023 and through 2030.[107] A total of 8,963 MW of capacity are at risk of retirement in 2023, consisting of 6,086 MW currently planning to retire in 2023 and 2,877 MW expected to retire by the end of 2023 for regulatory reasons. This capacity consists primarily of coal plants and gas peaker units. The units expected to retire by the end of 2023 generated 13,690.9 GWh in the first three months of 2023. The dashed line (green) in Figure 3-46 shows a counterfactual result for FDI_e assuming the 13,690.9 GWh of generation from uneconomic units and expected 2023 retirements were replaced by gas, wind and solar generation.[108] The FDI_e for the first three months of 2023 under this counterfactual assumption would have been 4.6 percent lower than the actual FDI_e. A total of 51,757 MW of capacity are at risk of retirement by the end of 2030, consisting of 6,628 MW currently planning to retire, 23,509 MW expected to retire for regulatory reasons, and 21,621 MW expected to be uneconomic. The identified units generated 16,641.1 GWh in the first three months of 2023. Replacing this generation with gas, wind and solar generation results in a counterfactual FDI_e that is 2.1 percent higher than the actual FDI_e.[109] The dashed line (blue) in Figure 3-46 shows a counterfactual result for FDI_e assuming that this generation is replaced with gas, wind and solar generation.

107 See Units At Risk of Retirement in the *2022 State of the Market Report for PJM*, Section 7: Net Revenue.
108 It is assumed that 2,694.9 GWh of the replacement energy is from new wind and solar units. This value represents the increase over 2023 levels in renewable generation that is required by RPS in the first three months of 2024. The split between solar (58.4 percent) and wind (41.6 percent) is based on queue data and 2023 capacity factors in Table 8-33 and Table 8-36.
109 It is assumed that 16,304.4 GWh of the replacement energy is from new wind and solar units. This value represents the increase over 2023 levels in renewable generation that is required by RPS in the first three months of 2030. The split between solar (58.4 percent) and wind (41.6 percent) is based on queue data and 2023 capacity factors in Table 8-33 and Table 8-36.

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



Natural Gas Supply Issues

Both pipeline transportation and commodity natural gas are needed to deliver natural gas to power plants. Generators have a number of options which vary by pipeline and market area. A generator could purchase a delivered service in which the seller bundles the transportation and commodity, purchased on a term contract or a spot basis. A generator could purchase pipeline transportation and purchase commodity natural gas separately with a term supply contract or through daily purchases in the spot market. Generators could purchase storage service. Storage services can be bundled with pipeline transportation, or storage and transportation purchased separately to move gas to or from a storage facility. The storage contracted service will determine the total storage capacity and the injection and withdrawal rights. Storage offers the owner the ability to have on demand supplies, or the ability to redirect unused supplies to storage. Predetermined allocation (PDA) nominations can be used to direct the pipeline as to how to treat an excess or a deficiency of gas at a delivery point. Combinations of these options are also available.

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

In order to be able to actually use the purchased pipeline transportation service, generation owners must nominate the flow of gas by defined deadlines. Some pipelines also impose site specific restrictions that limit the ability of generators to nominate and schedule gas beyond the nomination deadlines. Table 3-67 shows the approved nomination deadlines and corresponding start time of gas flow.[110] Pipelines provide that firm service requests may replace, or bump, interruptible nominations on the pipeline under defined conditions.

Table 3-67 Approved nomination deadlines

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

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

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

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

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

In general, the availability status of gas generators in the PJM energy market does not accurately reflect their ability to procure and nominate gas on the pipelines based on the rules defined by the pipelines. If the result of the pipeline rules is that some gas generators cannot reliably procure gas during the operating day in order to respond to PJM directions to generate, the result could be an inflated estimate of reserves on the PJM system, if the generator does not have back up fuel. Gas units should be required to be on forced outage if they cannot obtain gas during the operating day to meet their must offer requirement.

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

Types of Marginal Resources

LMPs result from the operation of a market based on security-constrained, least-cost dispatch in which marginal resources determine system LMPs, based on their offers. Marginal resource designation is not limited to physical resources in the day-ahead energy market. INC offers, DEC bids and up to congestion transactions are dispatchable injections and withdrawals in the day-ahead energy market that can set price via their offers and bids.

Table 3-68 shows the type of fuel used and technology by marginal resources in the real-time energy market. There can be more than one marginal resource in any given interval as a result of transmission constraints. In the first three months of 2023, coal units were 11.6 percent and natural gas units were 79.0 percent of marginal resources. In the first three months of 2023, natural gas combined cycle units were 70.5 percent of marginal resources. In the first three months of 2022, coal units were 15.3 percent and natural gas units were 63.6 percent of the total marginal resources. In the first three months of 2022, natural gas combined cycle units were 56.0 percent of the total marginal resources. In the first three months of 2023, 61.7 percent of the wind marginal units had negative offer prices, 36.4 percent had zero offer prices and 1.9 percent of the wind marginal units had positive offer prices. In the first three months of 2022, 45.7 percent of the wind marginal units had negative offer prices, 46.8 percent had zero offer prices and 7.5 percent had positive offer prices.

The proportion of marginal nuclear units decreased from 00.50 percent in the first three months of 2022 to 0.07 percent in the first three months of 2023. Most nuclear units are offered as fixed generation in the PJM market. A small number of nuclear units were offered with a dispatchable range since 2015. The dispatchable nuclear units do not always respond to dispatch instructions.

PJM implemented fast start pricing on September 1, 2021. The marginal resources shown in Table 3-68 are from the pricing run, which may not be the same as marginal resources from the dispatch run.

Table 3-68 Type of fuel used and technology (By real-time marginal units): January through March, 2019 through 2023[111]

		(Jan - Mar)				
Fuel	Technology	2019	2020	2021	2022	2023
Gas	CC	62.13%	71.55%	65.49%	56.05%	70.50%
Coal	Steam	24.37%	17.51%	17.95%	15.30%	11.65%
Wind	Wind	3.81%	7.17%	10.36%	14.11%	8.00%
Gas	CT	5.97%	0.02%	3.25%	5.96%	6.39%
Gas	RICE	0.00%	0.00%	0.25%	0.66%	1.39%
Gas	Steam	1.29%	1.48%	0.45%	0.95%	0.77%
Oil	CT	0.49%	0.60%	0.85%	5.70%	0.69%
Oil	CC	0.01%	0.00%	0.06%	0.08%	0.38%
Oil	RICE	0.00%	0.00%	0.12%	0.05%	0.08%
Uranium	Steam	1.31%	1.03%	0.55%	0.50%	0.07%
Other	Steam	0.06%	0.24%	0.10%	0.07%	0.05%
Municipal Waste	Steam	0.02%	0.02%	0.02%	0.02%	0.02%
Municipal Waste	RICE	0.00%	0.00%	0.00%	0.00%	0.02%
Landfill Gas	CT	0.01%	0.05%	0.01%	0.00%	0.00%
Municipal Waste	CT	0.00%	0.00%	0.00%	0.00%	0.00%
Gas	Fuel Cell	0.00%	0.00%	0.00%	0.00%	0.00%
Landfill Gas	Steam	0.00%	0.00%	0.00%	0.00%	0.00%
Coal	CT	0.00%	0.00%	0.00%	0.00%	0.00%
Landfill Gas	RICE	0.00%	0.00%	0.00%	0.00%	0.00%
Other	Solar	0.07%	0.33%	0.48%	0.53%	0.00%
Oil	Steam	0.03%	0.00%	0.05%	0.00%	0.00%

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

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

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

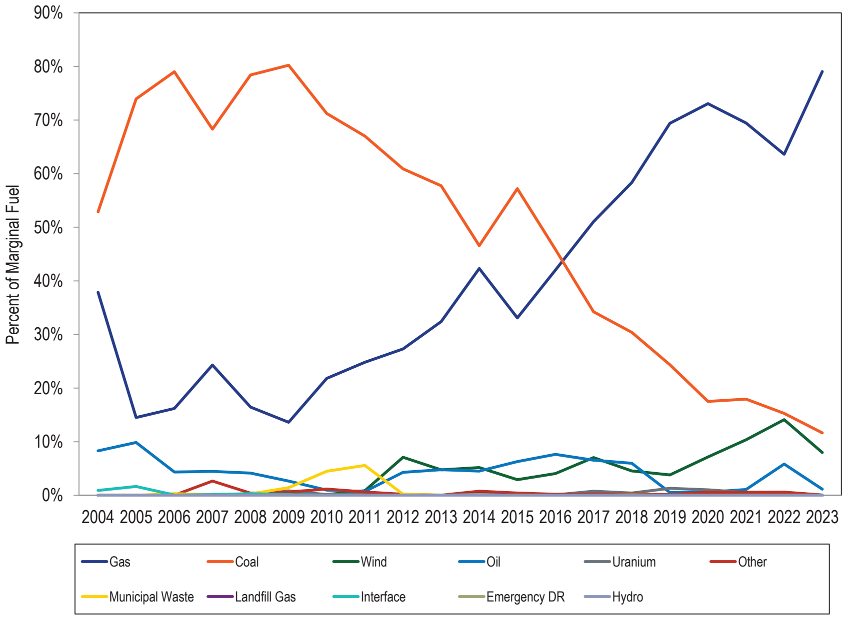


Table 3-69 shows the type of fuel and technology by fast start marginal resources and other marginal resources in the real-time energy market in the first three months of 2023. In the first three months of 2023, marginal fast start resources accounted for 5.59 percent of all marginal resources in the pricing run.

Table 3-69 Fuel type and technology (Real-time marginal units and fast start marginal units): January through March, 2023

		2023 (Jan - Mar)		
Fuel	Technology	Fast Start	Other	Both
Coal	Steam	0.00%	11.65%	11.65%
Gas	CC	0.00%	70.50%	70.50%
Gas	CT	3.86%	2.53%	6.39%
Gas	RICE	1.36%	0.03%	1.39%
Gas	Steam	0.00%	0.77%	0.77%
Landfill Gas	CT	0.00%	0.00%	0.00%
Municipal Waste	RICE	0.01%	0.00%	0.01%
Municipal Waste	Steam	0.00%	0.02%	0.02%
Oil	CC	0.00%	0.38%	0.38%
Oil	CT	0.23%	0.46%	0.69%
Oil	RICE	0.08%	0.00%	0.08%
Other	Steam	0.00%	0.05%	0.05%
Uranium	Steam	0.00%	0.07%	0.07%
Wind	Wind	0.05%	7.95%	8.00%
All Marginal Units		5.59%	94.41%	100.00%

Table 3-70 shows the fuel used and technology where relevant, of marginal resources in the day-ahead energy market.[112] In the first three months of 2023, up to congestion transactions were 57.3 percent of marginal resources compared to 37.4 percent in the first three months of 2022. In the first three months of 2023, virtual transactions were 87.4 percent of marginal resources compared to 82.4 percent in the first three months of 2022.

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

Table 3-70 Day-ahead marginal resources by type/fuel used and technology: January through March, 2019 through 2023

		(Jan - Mar)				
Type/Fuel	Technology	2019	2020	2021	2022	2023
Up to Congestion Transaction	NA	59.89%	48.54%	37.74%	37.36%	57.27%
DEC	NA	16.67%	12.63%	24.82%	24.87%	16.85%
INC	NA	11.88%	16.21%	16.72%	20.13%	13.30%
Gas	CC	6.32%	15.68%	12.60%	8.89%	6.85%
Coal	Steam	4.68%	5.94%	6.57%	6.35%	3.13%
Wind	Wind	0.11%	0.35%	0.70%	1.37%	1.56%
Dispatchable Transaction	NA	0.16%	0.08%	0.21%	0.12%	0.34%
Gas	Steam	0.09%	0.16%	0.18%	0.29%	0.26%
Gas	CT	0.10%	0.10%	0.07%	0.16%	0.16%
Price Sensitive Demand	NA	0.01%	0.00%	0.05%	0.03%	0.13%
Other	Solar	0.00%	0.01%	0.03%	0.01%	0.06%
Gas	RICE	0.06%	0.02%	0.09%	0.05%	0.04%
Oil	Steam	0.00%	0.00%	0.01%	0.00%	0.01%
Water	Hydro	0.00%	0.00%	0.00%	0.00%	0.01%
Oil	CT	0.00%	0.03%	0.03%	0.31%	0.00%
Oil	CC	0.00%	0.00%	0.02%	0.02%	0.00%
Municipal Waste	RICE	0.02%	0.01%	0.04%	0.00%	0.00%
Other	Steam	0.01%	0.01%	0.04%	0.02%	0.00%
Oil	RICE	0.00%	0.00%	0.02%	0.00%	0.00%
Uranium	Steam	0.00%	0.24%	0.07%	0.01%	0.00%
Total		100.00%	100.00%	100.00%	100.00%	100.00%

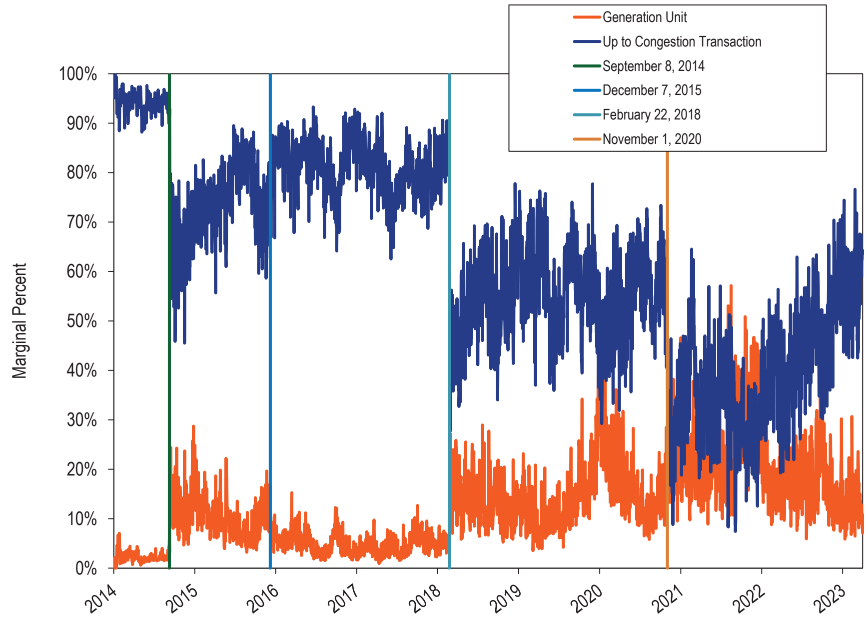
Figure 3-48 shows, for the day-ahead energy market from January 2014 through March 2023, the daily proportion of marginal resources that were up to congestion transactions or generation units.[113] The UTC share increased from 37.4 percent in the first three months of 2022 to 57.3 percent in the first three months of 2023.

Up to congestion transaction volumes decreased following the allocation of uplift charges on November 1, 2020, but increased in 2022.[114] The hourly average submitted up to congestion bid MW increased by 186.2 percent and cleared up to congestion bid MW increased by 135.2 percent in the first three months of 2023 compared to the first three months of 2022.

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

114 172 FERC ¶ 61,046 (2020).

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

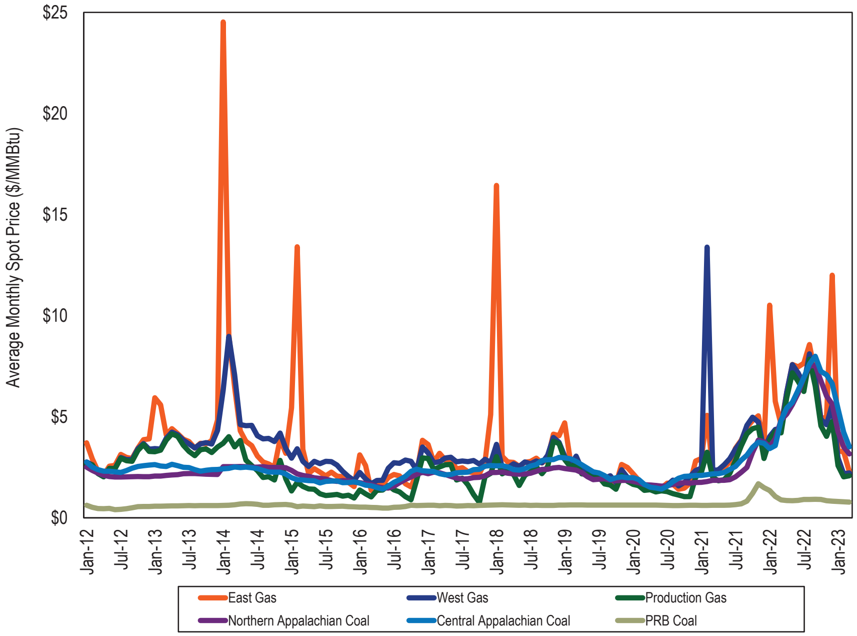


Fuel Price Trends and LMP

In a competitive market, changes in LMP follow changes in the marginal costs of marginal units, the units setting LMP. In general, fuel costs make up between 80 percent and 90 percent of short run marginal cost depending on generating technology, unit efficiency, unit age and other factors. The impact of fuel cost on marginal cost and on LMP depends on the fuel burned by marginal units and changes in fuel costs. Changes in emission allowance costs also contribute to changes in the marginal cost of marginal units.

Figure 3-49 shows fuel prices in PJM for 2012 through March 2023. Natural gas prices, some coal prices, and oil prices decreased in the first three months of 2023 compared to the first three months of 2022. The price of natural gas in the Marcellus Shale production area is lower than in other areas of PJM and a number of new combined cycle plants have located in the production area since 2016. In the first three months of 2023, the price of production gas was 45.7 percent lower than in the first three months of 2022, the price of eastern natural gas was 57.5 percent lower and the price of western natural gas was 42.6 percent lower. The price of Northern Appalachian coal was 10.9 percent lower; the price of Central Appalachian coal was 11.3 percent higher; and the price of Powder River Basin coal was 27.6 percent lower.[115] The price of ULSD NY Harbor Barge was 41.1 percent lower in the first three months of 2023 than in the first three months of 2022.

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



115 Eastern natural gas consists of the average of Texas M3, Transco Zone 6 non-NY, Transco Zone 6 NY and Transco Zone 5 daily indices. Western natural gas prices are the average of Columbia Appalachia and Chicago Citygate daily indices. Production gas prices are the average of Dominion South Point, Tennessee Zone 4, and Transco Leidy Line receipts daily indices. Coal prices are the average of daily fuel prices for Central Appalachian coal, Northern Appalachian coal, and Powder River Basin coal. All fuel prices are from Platts.

Components of LMP

Components of Real-Time Load-Weighted LMP

LMPs result from the operation of a market based on security-constrained, economic (least cost) dispatch (SCED) in which marginal units determine system LMPs, based on their offers and up to fourteen minute ahead forecasts of system conditions. Those offers can be decomposed into components including fuel costs, emission costs, variable operation and maintenance (VOM) costs, markup, FMU adder and the 10 percent cost adder. As a result, it is possible to decompose LMP by the components of unit offers.

Cost offers of marginal units are separated into their component parts. The fuel related component is based on unit specific heat rates and spot fuel prices. Emission costs are calculated using spot prices for NO_x, SO_2 and CO_2 emission credits, emission rates for NO_x, emission rates for SO_2 and emission rates for CO_2. The CO_2 emission costs are applicable to PJM units in the PJM states that participate in RGGI: Delaware, Maryland, New Jersey, and Virginia.[116] The FMU adder is the calculated contribution of the FMU and AU adders to LMP that results when units with FMU or AU adders are marginal.

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

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

requirements, the scarcity component, which is defined by the operating reserve demand curve.[117]

Starting on September 1, 2021, the components shown in Table 3-71 and Table 3-72 are from the pricing run which includes the impact of amortized start cost and amortized no load cost of the fast start marginal units. The components of LMP are shown in Table 3-71, including markup using unadjusted cost-based offers.[118] Table 3-71 shows that in the first three months of 2023, 18.2 percent of the load-weighted LMP was the result of coal costs, 53.7 percent was the result of gas costs and 5.3 percent was the result of the cost of carbon emission allowances. Using unadjusted cost-based offers, negative markup was -9.7 percent of the load-weighted LMP. Using unadjusted cost-based offers, positive markup was 10.0 percent of the load weighted LMP. The fuel-related components of LMP reflect the degree to which the cost of the identified fuel affects LMP and does not reflect the other components of the offers of units burning that fuel. LMP may, at times, be set by transmission penalty factors. When a transmission constraint is binding and there are no cheaper generation alternatives to resolve the constraint, system operators may allow the transmission limit to be violated. When this occurs, the shadow price of the constraint is set by transmission penalty factors. In the first three months of 2023, 2.5 percent of the load-weighted LMP was the result of transmission penalty factors affecting LMPs. The percent contribution of transmission penalty factors has increased substantially since PJM removed the constraint relaxation logic and allowed penalty factors to affect LMPs starting in February 2019. The component NA is the unexplained portion of load-weighted LMP. For several intervals, PJM failed to provide all the data needed to accurately calculate generator sensitivity factors. As a result, the LMP for those intervals cannot be decomposed into component costs. The NA component is the cumulative effect of excluding those five minute intervals. The percent column is the difference (in percentage points) in the proportion of LMP represented by each component in the first three months of 2022 and 2023.

117 Scarcity component includes ancillary service redispatch cost component during periods of scarcity.
118 These components are explained in the *Technical Reference for PJM Markets*, at p 27 "Calculation and Use of Generator Sensitivity/Unit Participation Factors," <http://www.monitoringanalytics.com/reports/Technical_References/references.shtml>.

Table 3-71 Components of real-time (Unadjusted) load-weighted average LMP: January through March 2022, and 2023

	2022 (Jan - Mar)		2023 (Jan - Mar)		
Element	Contribution to LMP	Percent	Contribution to LMP	Percent	Change in Percent
Gas	$27.46	50.7%	$16.25	53.7%	3.0%
Coal	$7.55	14.0%	$5.50	18.2%	4.2%
Positive Markup	$4.71	8.7%	$3.01	10.0%	1.2%
Variable Maintenance	$1.93	3.6%	$1.93	6.4%	2.8%
Ten Percent Adder	$3.53	6.5%	$1.88	6.2%	(0.3%)
CO_2 Cost	$1.68	3.1%	$1.61	5.3%	2.2%
Variable Operations	$0.97	1.8%	$1.02	3.4%	1.6%
Transmission Constraint Penalty Factor	$4.40	8.1%	$0.75	2.5%	(5.7%)
Opportunity Cost Adder	$0.29	0.5%	$0.26	0.9%	0.3%
NA	$0.34	0.6%	$0.19	0.6%	0.0%
Market-to-Market	$0.04	0.1%	$0.19	0.6%	0.6%
Oil	$0.86	1.6%	$0.18	0.6%	(1.0%)
LPA Rounding Difference	$0.78	1.4%	$0.15	0.5%	(0.9%)
Scarcity	$0.64	1.2%	$0.14	0.5%	(0.7%)
Ancillary Service Redispatch Cost	$1.73	3.2%	$0.09	0.3%	(2.9%)
Increase Generation Differential	$0.06	0.1%	$0.09	0.3%	0.2%
Other	$0.03	0.1%	$0.02	0.1%	0.0%
Landfill Gas	$0.01	0.0%	$0.01	0.0%	0.0%
NO_x Cost	$0.19	0.3%	$0.00	0.0%	(0.3%)
SO_2 Cost	$0.00	0.0%	$0.00	0.0%	0.0%
LPA-SCED Differential	($0.03)	(0.1%)	($0.00)	(0.0%)	0.1%
Decrease Generation Differential	($0.02)	(0.0%)	($0.01)	(0.0%)	0.0%
Renewable Energy Credits	($0.07)	(0.1%)	($0.04)	(0.1%)	0.0%
Negative Markup	($2.94)	(5.4%)	($2.94)	(9.7%)	(4.3%)
Total	$54.13	100.0%	$30.28	100.0%	0.0%

Change in Components of LMP

Table 3-73 shows the components of the decrease in real-time load-weighted average LMP from the first three months of 2022 to the first three months of 2023. In the first three months of 2023, the real-time load-weighted average LMP decreased by $23.85 per MWh, 44.1 percent. Most of the decrease, 58.2 percent of the decrease in LMP, was the result of the $13.89 per MWh decrease in the fuel and consumables cost components of LMP (the sum of gas, coal, oil, landfill gas, variable operations). The emissions cost components of LMP (the sum of NO_X, CO_2, opportunity cost adder, SO_2, and renewable energy credits) decreased the LMP by $0.26 per MWh, 1.1 percent of the decrease in LMP. The sum of the positive and negative markups, ten percent adder, and maintenance cost components, all of which reflect market power, decreased the LMP $3.35 per MWh, 14.0 percent of the decrease in LMP. The scarcity component decreased the LMP by $0.50 per MWh, 2.1 percent of the decrease in the LMP. The transmission constraint penalty factor decreased the LMP by $3.65 per MWh, 15.3 percent. The ancillary service redispatch cost, the opportunity cost of reduced marginal generation to meet reserve requirements, decreased the LMP by $1.64 per MWh, 6.9 percent.

In order to understand the markup behavior of market participants, real-time and day-ahead LMPs are decomposed using two different approaches. In the first approach (Table 3-71 and Table 3-76) markup is the difference between the price offer and the cost-based offer (unadjusted markup). In the second approach (Table 3-72 and Table 3-77), the 10 percent markup is removed from the cost-based offers of coal, gas, and oil units (adjusted markup).

The components of LMP are shown in Table 3-72, including markup using adjusted cost-based offers.

Table 3-72 Components of real-time (Adjusted) load-weighted average LMP: January through March, 2022 and 2023

	2022 (Jan - Mar)		2023 (Jan - Mar)		
Element	Contribution to LMP	Percent	Contribution to LMP	Percent	Change in Percent
Gas	$27.46	50.7%	$16.25	53.7%	3.0%
Coal	$7.55	14.0%	$5.50	18.2%	4.2%
Positive Markup	$6.80	12.6%	$3.90	12.9%	0.3%
Variable Maintenance	$1.93	3.6%	$1.93	6.4%	2.8%
CO_2 Cost	$1.68	3.1%	$1.61	5.3%	2.2%
Variable Operations	$0.97	1.8%	$1.02	3.4%	1.6%
Transmission Constraint Penalty Factor	$4.40	8.1%	$0.75	2.5%	(5.7%)
Opportunity Cost Adder	$0.29	0.5%	$0.26	0.9%	0.3%
NA	$0.34	0.6%	$0.19	0.6%	0.0%
Market-to-Market	$0.04	0.1%	$0.19	0.6%	0.6%
Oil	$0.86	1.6%	$0.18	0.6%	(1.0%)
LPA Rounding Difference	$0.78	1.4%	$0.15	0.5%	(0.9%)
Scarcity	$0.64	1.2%	$0.14	0.5%	(0.7%)
Ancillary Service Redispatch Cost	$1.73	3.2%	$0.09	0.3%	(2.9%)
Increase Generation Differential	$0.06	0.1%	$0.09	0.3%	0.2%
Other	$0.03	0.1%	$0.02	0.1%	0.0%
Landfill Gas	$0.01	0.0%	$0.01	0.0%	0.0%
Ten Percent Adder	$0.00	0.0%	$0.00	0.0%	0.0%
NO_x Cost	$0.19	0.3%	$0.00	0.0%	(0.3%)
SO_2 Cost	$0.00	0.0%	$0.00	0.0%	0.0%
LPA-SCED Differential	($0.03)	(0.1%)	($0.00)	(0.0%)	0.1%
Decrease Generation Differential	($0.02)	(0.0%)	($0.01)	(0.0%)	0.0%
Renewable Energy Credits	($0.07)	(0.1%)	($0.04)	(0.1%)	0.0%
Negative Markup	($1.51)	(2.8%)	($1.96)	(6.5%)	(3.7%)
Total	$54.13	100.0%	$30.28	100.0%	0.0%

PJM implemented fast start pricing on September 1, 2021. The commitment cost related components of LMP are shown in Table 3-74 including markup using unadjusted cost-based offers for the first three months of 2023. In the first three months of 2023, 1.6 percent of the load-weighted average LMP was the result of commitment costs. The majority of the commitment costs in LMP were fuel costs in the no load component of offers for gas fired fast start units. The second largest component was maintenance costs.

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

Component	2022 (Jan - Mar)	2023 (Jan - Mar)	Change in LMP	Percent
Fuel and Consumables	$36.86	$22.97	($13.89)	58.2%
Emission Related	$2.09	$1.84	($0.26)	1.1%
Market Power Related	$7.23	$3.88	($3.35)	14.0%
Scarcity	$0.64	$0.14	($0.50)	2.1%
Transmission Constraint Penalty Factor	$4.40	$0.75	($3.65)	15.3%
Ancillary Service Redispatch Cost	$1.73	$0.09	($1.64)	6.9%
Emergency Demand Response	$0.00	$0.00	$0.00	0.0%
PJM Administrative Cap	$0.00	$0.00	$0.00	0.0%
All Other	$1.19	$0.63	($0.56)	2.4%
Total	$54.13	$30.28	($23.85)	100.0%

Table 3-74 Commitment cost related components of real-time (Unadjusted) load-weighted average LMP: January through March, 2023

	Start Cost Components		No Load Components		Other Components		Total	
Element	Contribution to LMP	Percent	Contribution to LMP	Percent	Contribution to LMP	Percent	Contribution to LMP	Percent
Gas	$0.00	0.0%	$0.32	1.0%	$15.94	52.6%	$16.25	53.7%
Coal	$0.00	0.0%	$0.00	0.0%	$5.50	18.2%	$5.50	18.2%
Postive Markup	$0.02	0.1%	$0.00	0.0%	$3.00	9.9%	$3.01	10.0%
Variable Maintenance	$0.09	0.3%	$0.04	0.1%	$1.79	5.9%	$1.93	6.4%
Ten Percent Adder	$0.01	0.0%	$0.03	0.1%	$1.85	6.1%	$1.88	6.2%
CO_2 Cost	$0.00	0.0%	$0.01	0.0%	$1.60	5.3%	$1.61	5.3%
Variable Operations	$0.00	0.0%	$0.00	0.0%	$1.02	3.4%	$1.02	3.4%
Transmission Constraint Penalty Factor	$0.00	0.0%	$0.00	0.0%	$0.75	2.5%	$0.75	2.5%
NO_X Cost	$0.00	0.0%	$0.00	0.0%	$0.26	0.9%	$0.26	0.9%
NA	$0.00	0.0%	$0.00	0.0%	$0.19	0.6%	$0.19	0.6%
CO_2 Cost	$0.00	0.0%	$0.00	0.0%	$0.19	0.6%	$0.19	0.6%
Oil	$0.00	0.0%	$0.01	0.0%	$0.17	0.6%	$0.18	0.6%
LPA Rounding Difference	$0.00	0.0%	$0.00	0.0%	$0.15	0.5%	$0.15	0.5%
Scarcity	$0.00	0.0%	$0.00	0.0%	$0.14	0.5%	$0.14	0.5%
Ancillary Service Redispatch Cost	$0.00	0.0%	$0.00	0.0%	$0.09	0.3%	$0.09	0.3%
Increase Generation Differential	$0.00	0.0%	$0.00	0.0%	$0.09	0.3%	$0.09	0.3%
Other	$0.00	0.0%	$0.00	0.0%	$0.02	0.1%	$0.02	0.1%
Landfill Gas	$0.00	0.0%	$0.00	0.0%	$0.01	0.0%	$0.01	0.0%
NO_X Cost	$0.00	0.0%	$0.00	0.0%	$0.00	0.0%	$0.00	0.0%
SO_2 Cost	$0.00	0.0%	$0.00	0.0%	$0.00	0.0%	$0.00	0.0%
SO_2 Cost	$0.00	0.0%	$0.00	0.0%	($0.00)	(0.0%)	($0.00)	(0.0%)
Decrease Generation Differential	$0.00	0.0%	$0.00	0.0%	($0.01)	(0.0%)	($0.01)	(0.0%)
Renewable Energy Credits	$0.00	0.0%	$0.00	0.0%	($0.04)	(0.1%)	($0.04)	(0.1%)
Negative Markup	($0.03)	(0.1%)	($0.01)	(0.0%)	($2.91)	(9.6%)	($2.94)	(9.7%)
Total	$0.09	0.3%	$0.40	1.3%	$29.79	98.4%	$30.28	100.0%

The components of LMP for the dispatch run and the pricing run are shown in Table 3-75, including markup using unadjusted cost-based offers for the first three months of 2023.

Table 3-75 Comparison of components of real-time (Unadjusted) load-weighted average LMP in the dispatch run and pricing run: January through March, 2023

	Dispatch		Pricing		
Element	Contribution to LMP	Percent	Contribution to LMP	Percent	Change in Percent
Gas	$15.68	53.3%	$16.25	53.7%	0.4%
Coal	$5.63	19.1%	$5.50	18.2%	(1.0%)
Positive Markup	$2.81	9.6%	$3.01	10.0%	0.4%
Variable Maintenance	$1.72	5.9%	$1.93	6.4%	0.5%
Ten Percent Adder	$1.84	6.2%	$1.88	6.2%	(0.0%)
CO_2 Cost	$1.58	5.4%	$1.61	5.3%	(0.1%)
Variable Operations	$1.01	3.4%	$1.02	3.4%	(0.1%)
Transmission Constraint Penalty Factor	$0.74	2.5%	$0.75	2.5%	(0.0%)
NO_x Cost	$0.26	0.9%	$0.26	0.9%	(0.0%)
NA	$0.01	0.0%	$0.19	0.6%	0.6%
CO_2 Cost	$0.21	0.7%	$0.19	0.6%	(0.1%)
Oil	$0.19	0.7%	$0.18	0.6%	(0.1%)
LPA Rounding Difference	$0.12	0.4%	$0.15	0.5%	0.1%
Scarcity	$0.13	0.4%	$0.14	0.5%	0.0%
Ancillary Service Redispatch Cost	$0.21	0.7%	$0.09	0.3%	(0.4%)
Increase Generation Differential	$0.21	0.7%	$0.09	0.3%	(0.4%)
Other	$0.03	0.1%	$0.02	0.1%	(0.0%)
Landfill Gas	$0.02	0.1%	$0.01	0.0%	(0.0%)
NO_x Cost	$0.00	0.0%	$0.00	0.0%	0.0%
SO_2 Cost	$0.00	0.0%	$0.00	0.0%	(0.0%)
SO_2 Cost	($0.00)	(0.0%)	($0.00)	(0.0%)	0.0%
Decrease Generation Differential	($0.00)	(0.0%)	($0.01)	(0.0%)	(0.0%)
Renewable Energy Credits	($0.03)	(0.1%)	($0.04)	(0.1%)	(0.0%)
Negative Markup	($2.95)	(10.0%)	($2.94)	(9.7%)	0.3%
Total	$29.43	100.0%	$30.28	100.0%	0.0%

Components of Day-Ahead Load-Weighted LMP

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

Table 3-76 shows the components of the PJM day-ahead annual load-weighted average LMP. In the first three months of 2023, 23.4 percent of the load-weighted LMP was the result of gas costs, 20.5 percent of the load-weighted LMP was the result of coal costs, 16.9 percent was the result of DECs, 21.9 percent was the result of INCs, 3.0 percent was the result of UTCs and 7.9 percent was the result of positive markup.[119]

Table 3-76 Components of day-ahead (Unadjusted) load-weighted average LMP (Dollars per MWh): January through March, 2022 and 2023

	2022 (Jan - Mar)		2023 (Jan - Mar)		
Element	Contribution to LMP	Percent	Contribution to LMP	Percent	Change in Percent
Gas	$12.58	23.3%	$7.50	23.4%	0.1%
INC	$8.47	15.7%	$7.03	21.9%	6.2%
Coal	$8.00	14.8%	$6.57	20.5%	5.6%
DEC	$15.25	28.3%	$5.42	16.9%	(11.4%)
Positive Markup	$4.14	7.7%	$2.53	7.9%	0.2%
Ten Percent Adder	$2.00	3.7%	$1.16	3.6%	(0.1%)
Up to Congestion Transaction	$1.40	2.6%	$0.96	3.0%	0.4%
Variable Operations	$0.82	1.5%	$0.89	2.8%	1.2%
Variable Maintenance	$0.85	1.6%	$0.89	2.8%	1.2%
CO_2 Cost	$1.15	2.1%	$0.81	2.5%	0.4%
Dispatchable Transaction	$0.19	0.4%	$0.41	1.3%	0.9%
Price Sensitive Demand	$0.22	0.4%	$0.22	0.7%	0.3%
Opportunity Cost Adder	$0.00	0.0%	$0.05	0.2%	0.1%
Oil	$0.06	0.1%	$0.01	0.0%	(0.1%)
SO_2 Cost	$0.00	0.0%	$0.00	0.0%	0.0%
NO_x Cost	$0.12	0.2%	$0.00	0.0%	(0.2%)
Wind	($0.25)	(0.5%)	($0.23)	(0.7%)	(0.3%)
Negative Markup	($1.07)	(2.0%)	($2.09)	(6.5%)	(4.5%)
Municipal Waste	$0.00	0.0%	$0.00	0.0%	(0.0%)
Other	$0.01	0.0%	$0.00	0.0%	(0.0%)
Uranium	$0.00	0.0%	$0.00	0.0%	(0.0%)
NA	$0.00	0.0%	$0.00	0.0%	0.0%
Total	$53.95	100.0%	$32.11	100.0%	0.0%

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

Table 3-77 shows the components of the PJM day-ahead annual load-weighted average LMP including the adjusted markup calculated by excluding the 10 percent adder from the coal, gas and oil units.[120]

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

	2022 (Jan - Mar)		2023 (Jan- Mar)		
Element	Contribution to LMP	Percent	Contribution to LMP	Percent	Change in Percent
Gas	$12.58	23.3%	$7.50	23.4%	0.1%
INC	$8.47	15.7%	$7.03	21.9%	6.2%
Coal	$8.00	14.8%	$6.57	20.5%	5.6%
DEC	$15.25	28.3%	$5.42	16.9%	(11.4%)
Positive Markup	$5.56	10.3%	$3.01	9.4%	(0.9%)
Up to Congestion Transaction	$1.40	2.6%	$0.96	3.0%	0.4%
Variable Operations	$0.82	1.5%	$0.89	2.8%	1.2%
Variable Maintenance	$0.85	1.6%	$0.89	2.8%	1.2%
CO_2 Cost	$1.15	2.1%	$0.81	2.5%	0.4%
Dispatchable Transaction	$0.19	0.4%	$0.41	1.3%	0.9%
Price Sensitive Demand	$0.22	0.4%	$0.22	0.7%	0.3%
Opportunity Cost Adder	$0.00	0.0%	$0.05	0.2%	0.1%
Oil	$0.06	0.1%	$0.01	0.0%	(0.1%)
SO_2 Cost	$0.00	0.0%	$0.00	0.0%	0.0%
NO_x Cost	$0.12	0.2%	$0.00	0.0%	(0.2%)
Ten Percent Adder	$0.00	0.0%	$0.00	0.0%	0.0%
Wind	($0.25)	(0.5%)	($0.23)	(0.7%)	(0.3%)
Negative Markup	($0.48)	(0.9%)	($1.41)	(4.4%)	(3.5%)
Municipal Waste	$0.00	0.0%	$0.00	0.0%	(0.0%)
Other	$0.01	0.0%	$0.00	0.0%	(0.0%)
Uranium	$0.00	0.0%	$0.00	0.0%	(0.0%)
NA	$0.00	0.0%	$0.00	0.0%	0.0%
Total	$53.95	100.0%	$32.11	100.0%	(0.0%)

Table 3-78 shows the change in the components of day-ahead load-weighted average LMP from the first three months of 2022 to the first three months of 2023. In the first three months of 2023, the day-ahead load-weighted average LMP decreased by $21.83 per MWh, 40.5 percent, compared to the first three months of 2022. Most of the decrease is due to the $9.83 per MWh decrease in the DEC component of LMP, which contributed 45.0 percent of the decrease in LMP. The second largest component of the decrease was the $6.54 per MWh decrease in fuel and consumables cost components of LMP (the sum of gas, coal, oil, and landfill gas), which contributed 29.9 percent of the decrease in LMP.

Table 3-78 Change in components of day-ahead load-weighted average LMP: January through March, 2022 and 2023

Element	2022 (Jan - Mar)	2023 (Jan - Mar)	Change in LMP	Percent
DEC	$15.25	$5.42	($9.83)	45.0%
Fuel	$20.39	$13.85	($6.54)	29.9%
Markup	$3.07	$0.44	($2.63)	12.1%
INC	$8.47	$7.03	($1.44)	6.6%
Ten Percent Adder	$2.00	$1.16	($0.84)	3.9%
Emissions	$1.27	$0.81	($0.46)	2.1%
Up to Congestion Transaction	$1.40	$0.96	($0.44)	2.0%
Other	$0.23	$0.26	$0.03	(0.2%)
Variable Maintenance and Operations	$1.67	$1.77	$0.10	(0.5%)
Dispatchable Transaction	$0.19	$0.41	$0.22	(1.0%)
Total	$53.95	$32.11	($21.83)	100.0%

120 Id.

Components of LMP Payments by Load

Table 3-79 shows the components of load payment in the first three months of 2023 and 2022 using unadjusted cost based offers.[121] Of the $6,069.8 million paid by PJM load in the first three months of 2023, the cost of gas accounted for $1,424.1 million or 23.5 percent. Table 3-80 shows the components of load payment in the first three months of 2023 and 2022 using adjusted cost based offers.

Table 3-79 Components (unadjusted) of load payment ($ Million): January through March, 2022 and 2023

	2022 (Jan - Mar)				2023 (Jan - Mar)			
Element	Day Ahead	Balancing	Total	Percent	Day Ahead	Balancing	Total	Percent
Gas	$2,463.3	$96.5	$2,559.9	23.8%	$1,400.9	$23.3	$1,424.1	23.5%
INC	$1,651.7	$0.0	$1,651.7	15.4%	$1,312.3	$0.0	$1,312.3	21.6%
Coal	$1,572.2	$29.8	$1,602.0	14.9%	$1,234.0	$18.5	$1,252.6	20.6%
DEC	$2,922.7	$0.0	$2,922.7	27.2%	$995.9	$0.0	$995.9	16.4%
Positive Markup	$813.3	$23.5	$836.8	7.8%	$477.4	$9.3	$486.8	8.0%
Ten Percent Adder	$393.3	$13.4	$406.7	3.8%	$217.6	$4.0	$221.6	3.7%
Up to Congestion Transaction	$258.2	$0.0	$258.2	2.4%	$182.0	$0.0	$182.0	3.0%
Variable Maintenance	$167.1	$7.3	$174.3	1.6%	$173.4	$3.4	$176.8	2.9%
Variable Operations	$161.2	$3.6	$164.8	1.5%	$167.4	$2.4	$169.8	2.8%
CO_2 Cost	$225.8	$5.9	$231.8	2.2%	$150.5	$2.4	$152.9	2.5%
Dispatchable Transaction	$37.4	$0.0	$37.4	0.3%	$74.3	$0.0	$74.3	1.2%
Price Sensitive Demand	$42.1	$0.0	$42.1	0.4%	$40.2	$0.0	$40.2	0.7%
Opportunity Cost Adder	$0.6	$1.4	$2.0	0.0%	$9.2	$1.2	$10.4	0.2%
Transmission Constraint Penalty Factor	$0.0	$40.4	$40.4	0.4%	$0.0	$6.6	$6.6	0.1%
Oil	$6.8	$8.3	$15.2	0.1%	$1.2	$0.7	$1.8	0.0%
Market-to-Market	$0.0	($1.7)	($1.7)	(0.0%)	$0.0	$1.4	$1.4	0.0%
Other	$3.9	$0.1	$4.1	0.0%	$1.0	$0.1	$1.1	0.0%
Scarcity	$0.0	$3.7	$3.7	0.0%	$0.0	$0.7	$0.7	0.0%
Oil	$0.0	$8.3	$8.3	0.1%	$0.1	$0.7	$0.7	0.0%
LPA Rounding Difference	$0.0	$4.6	$4.6	0.0%	$0.0	$0.7	$0.7	0.0%
Oil	$4.9	$8.3	$13.3	0.1%	$0.0	$0.7	$0.7	0.0%
Ancillary Service Redispatch Cost	$0.0	$11.6	$11.6	0.1%	$0.0	$0.5	$0.5	0.0%
Increase Generation Differential	$0.0	$0.6	$0.6	0.0%	$0.0	$0.3	$0.3	0.0%
Other	$1.6	$0.1	$1.8	0.0%	$0.0	$0.1	$0.1	0.0%
SO_2 Cost	$0.1	$0.0	$0.1	0.0%	$0.1	$0.0	$0.1	0.0%
Renewable Energy Credits	$0.0	($0.1)	($0.1)	(0.0%)	$0.0	$0.1	$0.1	0.0%
Landfill Gas	$0.1	$0.0	$0.2	0.0%	$0.0	$0.1	$0.1	0.0%
NO_x Cost	$22.7	$1.1	$23.8	0.2%	$0.1	$0.0	$0.1	0.0%
Decrease Generation Differential	$0.0	($0.1)	($0.1)	(0.0%)	$0.0	$0.0	$0.0	0.0%
LPA-SCED Differential	$0.0	($0.2)	($0.2)	(0.0%)	$0.0	$0.0	$0.0	0.0%
Uranium	$0.0	$0.0	$0.0	0.0%	$0.0	$0.0	$0.0	0.0%
NA	$0.0	$6.0	$6.0	0.1%	$0.0	($4.1)	($4.1)	(0.1%)
Wind	($48.9)	$0.0	($48.9)	(0.5%)	($42.6)	$0.0	($42.6)	(0.7%)
Negative Markup	($211.1)	($8.7)	($219.8)	(2.0%)	($392.6)	($5.4)	($398.0)	(6.6%)
Total	$10,489.2	$263.9	$10,753.1	100.0%	$6,002.1	$67.7	$6,069.8	100.0%

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

Table 3-80 Components (adjusted) of load payment ($ Million): January through March, 2022 and 2023

	2022 (Jan - Mar)				2023 (Jan - Mar)			
Element	Day Ahead	Balancing	Total	Percent	Day Ahead	Balancing	Total	Percent
Gas	$2,463.3	$96.5	$2,559.9	23.8%	$1,400.9	$23.3	$1,424.1	23.5%
INC	$1,651.7	$0.0	$1,651.7	15.4%	$1,312.3	$0.0	$1,312.3	21.6%
Coal	$1,572.2	$29.8	$1,602.0	14.9%	$1,234.0	$18.5	$1,252.6	20.6%
DEC	$2,922.7	$0.0	$2,922.7	27.2%	$995.9	$0.0	$995.9	16.4%
Positive Markup	$1,090.8	$32.5	$1,123.3	10.4%	$568.3	$11.6	$579.9	9.6%
Up to Congestion Transaction	$258.2	$0.0	$258.2	2.4%	$182.0	$0.0	$182.0	3.0%
Variable Maintenance	$167.1	$7.3	$174.3	1.6%	$173.4	$3.4	$176.8	2.9%
Variable Operations	$161.2	$3.6	$164.8	1.5%	$167.4	$2.4	$169.8	2.8%
CO_2 Cost	$225.8	$5.9	$231.8	2.2%	$150.5	$2.4	$152.9	2.5%
Dispatchable Transaction	$37.4	$0.0	$37.4	0.3%	$74.3	$0.0	$74.3	1.2%
Price Sensitive Demand	$42.1	$0.0	$42.1	0.4%	$40.2	$0.0	$40.2	0.7%
Opportunity Cost Adder	$0.6	$1.4	$2.0	0.0%	$9.2	$1.2	$10.4	0.2%
Transmission Constraint Penalty Factor	$0.0	$40.4	$40.4	0.4%	$0.0	$6.6	$6.6	0.1%
Oil	$6.8	$8.3	$15.2	0.1%	$1.2	$0.7	$1.8	0.0%
Market-to-Market	$0.0	($1.7)	($1.7)	(0.0%)	$0.0	$1.4	$1.4	0.0%
Other	$3.9	$0.1	$4.1	0.0%	$1.0	$0.1	$1.1	0.0%
Scarcity	$0.0	$3.7	$3.7	0.0%	$0.0	$0.7	$0.7	0.0%
Oil	$0.0	$8.3	$8.3	0.1%	$0.1	$0.7	$0.7	0.0%
LPA Rounding Difference	$0.0	$4.6	$4.6	0.0%	$0.0	$0.7	$0.7	0.0%
Oil	$4.9	$8.3	$13.3	0.1%	$0.0	$0.7	$0.7	0.0%
Ancillary Service Redispatch Cost	$0.0	$11.6	$11.6	0.1%	$0.0	$0.5	$0.5	0.0%
Increase Generation Differential	$0.0	$0.6	$0.6	0.0%	$0.0	$0.3	$0.3	0.0%
Other	$1.6	$0.1	$1.8	0.0%	$0.0	$0.1	$0.1	0.0%
SO_2 Cost	$0.1	$0.0	$0.1	0.0%	$0.1	$0.0	$0.1	0.0%
Renewable Energy Credits	$0.0	($0.1)	($0.1)	(0.0%)	$0.0	$0.1	$0.1	0.0%
Landfill Gas	$0.1	$0.0	$0.2	0.0%	$0.0	$0.1	$0.1	0.0%
NO_x Cost	$22.7	$1.1	$23.8	0.2%	$0.1	$0.0	$0.1	0.0%
Ten Percent Adder	$0.0	$0.0	$0.0	0.0%	$0.0	$0.0	$0.0	0.0%
Decrease Generation Differential	$0.0	($0.1)	($0.1)	(0.0%)	$0.0	$0.0	$0.0	0.0%
LPA-SCED Differential	$0.0	($0.2)	($0.2)	(0.0%)	$0.0	$0.0	$0.0	0.0%
Uranium	$0.0	$0.0	$0.0	0.0%	$0.0	$0.0	$0.0	0.0%
NA	$0.0	$6.0	$6.0	0.1%	$0.0	($4.1)	($4.1)	(0.1%)
Wind	($48.9)	$0.0	($48.9)	(0.5%)	($42.6)	$0.0	($42.6)	(0.7%)
Negative Markup	($95.3)	($4.3)	($99.7)	(0.9%)	($265.9)	($3.7)	($269.6)	(4.4%)
Total	$10,489.2	$263.9	$10,753.1	100.0%	$6,002.1	$67.7	$6,069.8	100.0%

Shortage

PJM's energy market experienced five minute shortage pricing for three five minute intervals on one day in the first three months of 2023. PJM implemented fast start pricing on September 1, 2021. In the first three months of 2023, there were three five minute intervals with shortage pricing in the pricing run, and three intervals with shortage in the dispatch run. Table 3-81 shows a summary of the number of days of the emergency alerts, warnings and actions that were declared in PJM in the first three months of 2022 and the first three months of 2023. In the first three months of 2023, there were zero days with emergency actions that triggered Performance Assessment Intervals (PAI).

Table 3-81 Summary of emergency events declared: January through March, 2022 and 2023

	Number of days events declared	
Event Type	2022 (Jan-Mar)	2023 (Jan-Mar)
Cold Weather Alert	7	3
Hot Weather Alert	0	0
Maximum Emergency Generation Alert	0	0
Primary Reserve Alert	0	0
Voltage Reduction Alert	0	0
Primary Reserve Warning	0	0
Voltage Reduction Warning	0	0
Pre Emergency Mandatory Load Management Reduction Action	0	0
Emergency Mandatory Load Management Reduction Action (30, 60 or 120 minute lead time)	0	0
Maximum Emergency Action	0	0
Emergency Energy Bids Requested	0	0
Voltage Reduction Action	0	0
Shortage Pricing	9	1
Energy export recalls from PJM capacity resources	0	0

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

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

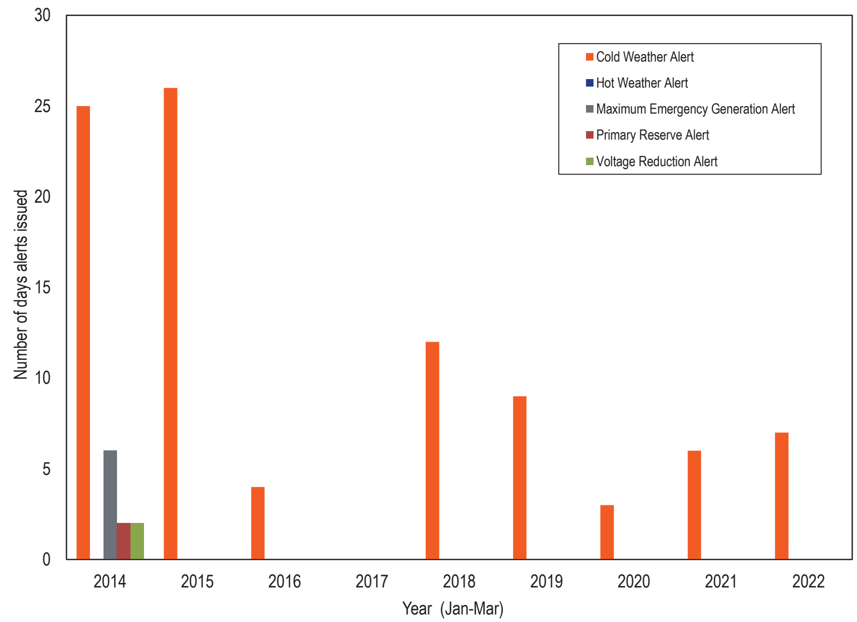
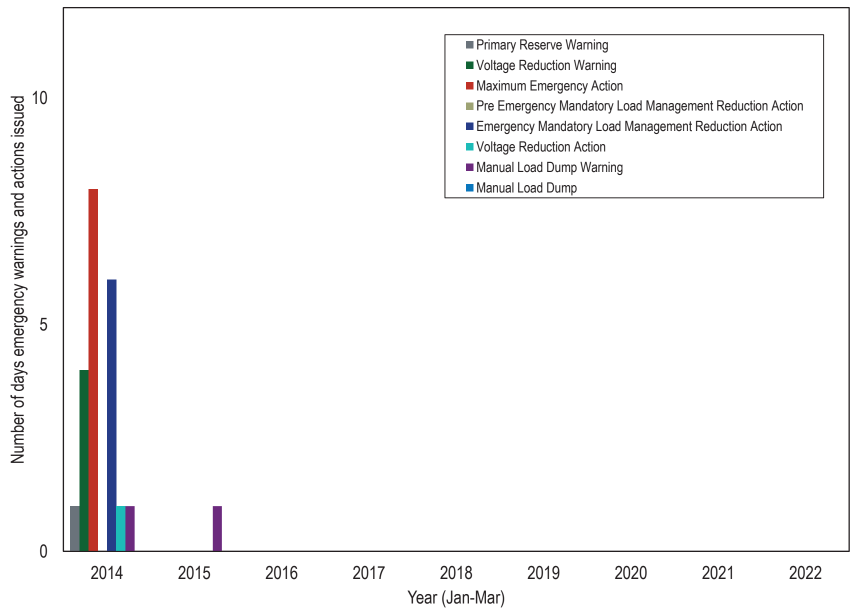


Figure 3-51 shows the number of days that emergency warnings and actions were declared in PJM in the first three months of the year from 2014 through 2023.

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



Emergency Procedures

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

Table 3-82 provides a description of PJM declared emergency procedures.[122] [123] [124] [125]

Table 3-82 Description of emergency procedures

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

122 See PJM. "Manual 13: Emergency Operations," Rev. 85 (Oct. 1, 2022), Section 3.3 Cold Weather Alert.
123 See PJM. "Manual 13: Emergency Operations," Rev. 85 (Oct. 1, 2022), Section 3.4 Hot Weather Alert.
124 See PJM. "Manual 13: Emergency Operations," Rev. 85 (Oct. 1, 2022), Section 2.3.1 Advanced Notice Emergency Procedures: Alerts.
125 See PJM. "Manual 13: Emergency Operations," Rev. 85 (Oct. 1, 2022), Section 2.3.2 Real-Time Emergency Procedures (Warnings and Actions).

Table 3-83 shows the dates when emergency alerts and warnings were declared and when emergency actions were implemented in the first three months of 2023.

Table 3-83 Declared emergency alerts, warnings and actions: January through March, 2023

Date	Cold Weather Alert	Hot Weather Alert	Maximum Emergency Generation Alert	Primary Reserve Alert	Voltage Reduction Alert	Primary Reserve Warning	Voltage Reduction Warning and Reduction of Non-Critical Plant Load	Maximum Emergency Generation Action	Pre-Emergency Mandatory Load Management Reduction	Emergency Mandatory Load Management Reduction	Voltage Reduction	Manual Load Dump Warning	Manual Load Dump Action	Load Shed Directive
31-Jan-2023	COMED													
03-Feb-2023	PJM RTO													

Power Balance Constraint Violation

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

The current process for meeting energy and reserve requirements in real time, and pricing the system conditions when RT SCED forecasts that energy supply is less than the demand for energy and reserves, is opaque and not defined in the PJM governing documents. It is unclear whether and how PJM converts reserves to energy before violating the power balance constraint. It is unclear whether and when PJM uses its authority under the tariff to curtail exports from PJM capacity resources to meet the power balance constraint. It is unclear whether PJM would maintain a minimum level of synchronized reserves even if that would result in a controlled load shed. The current RT SCED does not have a mechanism to convert inflexible reserves procured by the ASO to energy to satisfy the power balance constraint.[126] SCED solutions from October 1, 2019, February 16, 2020, and April 21, 2020, indicate that the currently defined logic meets transmission constraint limits and reserve requirements but violates the power balance constraint, and does not reflect this constraint violation in prices. This logic, if correctly described and if there was an actual power balance constraint violation, is not consistent with basic economics. The overall solution is complex and must be integrated with the approach to shortage pricing.

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

The MMU recommends that PJM clarify, modify and document its process for dispatching reserves and energy when SCED indicates that supply is less than total demand including forecasted load and reserve requirements. The modifications should define: a SCED process to economically convert reserves to energy; a process for the recall of energy from capacity resources; and the minimum level of synchronized reserves that would trigger load shedding. Table 3-84 shows the number of five minute intervals for which the RT SCED solutions did not balance demand and supply. PJM reran the RT SCED with artificially increased supply to satisfy the power balance constraint. In the first three months of 2023, there were 13 five minute intervals using an RT SCED solution with a violated power balance constraint. PJM ignored (relaxed) the power balance constraints in the first three months of 2023 and, as a result,

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

the power balance violation was not included in prices. It is unclear how PJM calculates prices when the power balance constraint is violated.

Table 3-84 Number of five minute intervals using RT SCED solutions with violated power balance constraint by year

Year	Number of five minute intervals	Average Energy Component of LMP in SCED ($/MWh)	Average Energy Component of LMP in Pricing Run ($/MWh)
2013	-	$0.00	$0.00
2014	655	$36.29	$36.29
2015	71	($0.76)	($0.76)
2016	42	$93.06	$93.06
2017	31	$279.86	$279.86
2018	16	$268.21	$268.21
2019	36	$845.48	$845.48
2020	5	$351.56	$351.56
2021	10	$976.06	$976.06
2022	121	$2,347.33	$2,066.21
2023 (Jan - Mar)	13	$393.66	$393.13

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

Figure 3-52 Power balance constraint violations: December 23

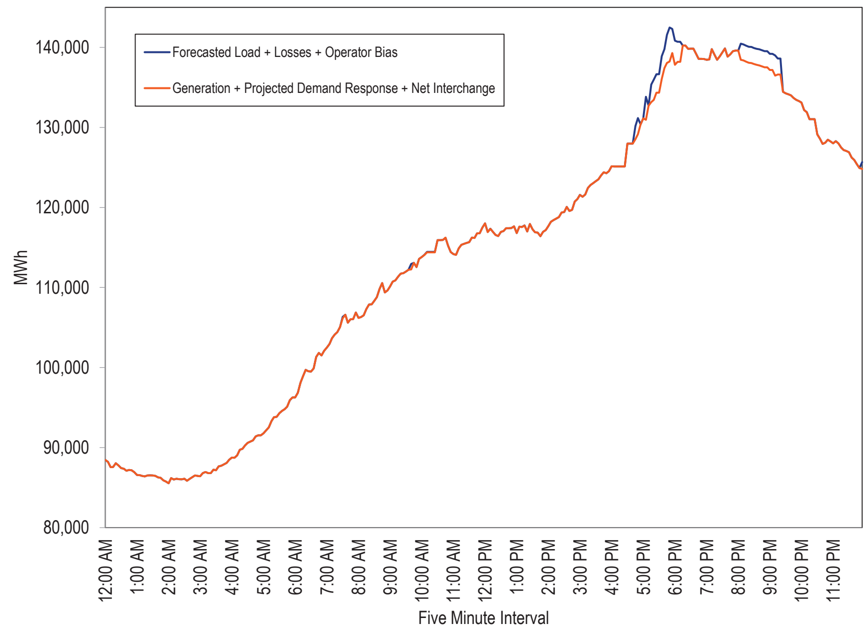
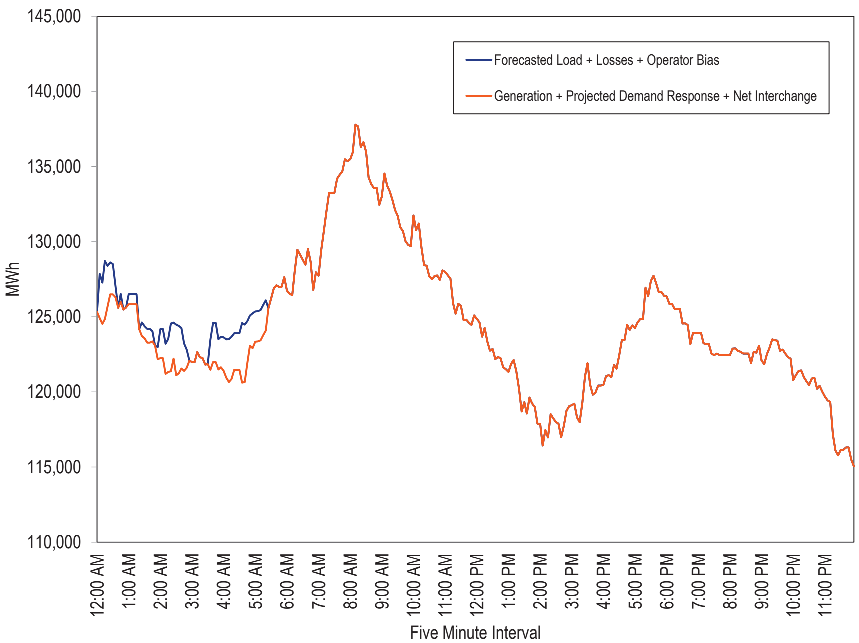


Figure 3-53 Power balance constraint violations: December 24



Shortage and Shortage Pricing

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

In the first three months of 2023, there were three five minute intervals with shortage pricing that occurred on one day in PJM.

In Order No. 825, the Commission required each RTO/ISO to trigger shortage pricing for any dispatch and pricing interval in which a shortage of energy or operating reserves is indicated by the RTO/ISO's software.[127] Prior to May 11, 2017, if the dispatch tools (Intermediate-Term SCED and Real-Time SCED) reflected a shortage of reserves (primary or synchronized) for a time period shorter than a defined threshold (30 minutes), it was considered a transient shortage, a shortage event was not declared, and shortage pricing was not implemented. As of May 11, 2017, the rule requires PJM to trigger shortage pricing for any five minute interval for which the Real-Time SCED (Security Constrained Economic Dispatch) indicates a shortage of synchronized reserves or primary reserves. In January 2019, PJM updated its business rules in Manual 11 to describe PJM's implementation of the five minute shortage pricing process. PJM Manual 11 states that shortage pricing is triggered when an approved RT SCED case that was used in the Locational Pricing Calculator (LPC) indicates a shortage of reserves. The implementation is not as algorithmic as intended by Order No. 825, because RT SCED can indicate a shortage that PJM does not use in pricing. On June 22, 2020, PJM reduced the frequency of automatic RT SCED executions to match the frequency of pricing at five minutes, which reduced the frequency of unpriced shortage solutions.

Prior to September 1, 2021, the reserves calculated in the LPC solution, and the reserves calculated in the reference RT SCED case used by the LPC solution were the same. With the implementation of fast start pricing on September 1, 2021, shortage pricing is now triggered by the pricing run in LPC.[128] This can lead to differences between the dispatched reserves in RT SCED, and the reserves calculated in the pricing run in LPC. In the pricing run in LPC, shortage pricing could be triggered even when there is no actual shortage in dispatched reserves as determined by the reference RT SCED solution. This occurred during zero intervals in the first three months of 2023.[129]

127 *Settlement Intervals and Shortage Pricing in Markets Operated by Regional Transmission Organizations and Independent System Operators*, Order No. 825, 155 FERC ¶ 61,276 at P 162 (2016).
128 *See* PJM Operating Agreement, Schedule 1, Section 2.5.1(a).
129 The seven intervals include a case in which both RTO and MAD were short in the pricing run but only MAD was short in the dispatch run.

Voltage reduction actions and manual load dump actions are also triggers for shortage pricing, reflecting the fact that when operators need to take these emergency actions to maintain reliability, the system is short reserves and prices should reflect that condition, even if the data do not show a shortage of reserves.[130]

Operating Reserve Demand Curves

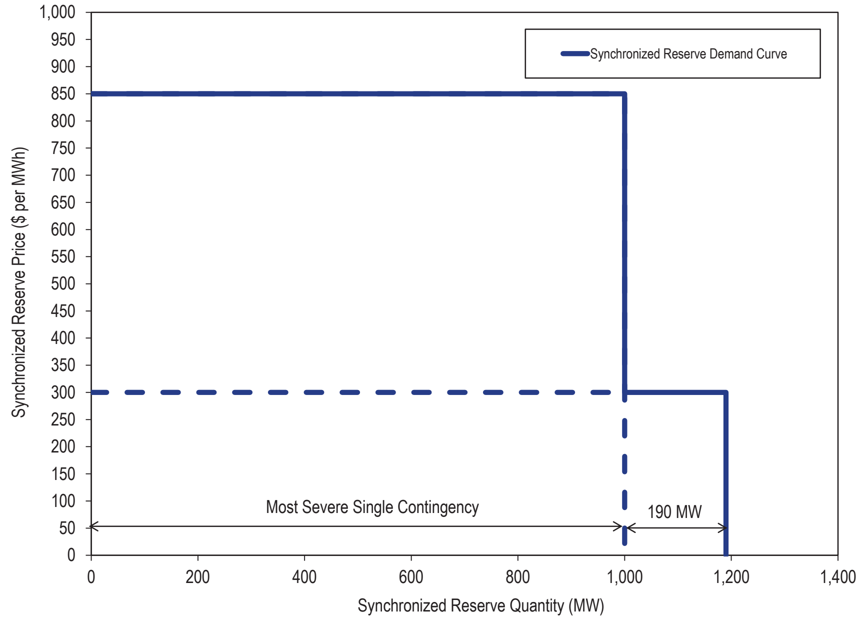
Shortage pricing in the PJM Energy Market can occur in either the day-ahead or the real-time market for any of five reserves requirements: RTO Synchronized Reserves, Subzone Synchronized Reserves, RTO Primary Reserves, Subzone Primary Reserves, and 30 Minute Reserves. Each requirement is modelled in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

Shortage Pricing and Energy Price Formation

The current operating reserve demand curves (ORDC) in PJM define an administrative price for estimated reserves (primary and synchronized reserves) up to the extended reserve requirement quantities. The demand curve shown in Figure 3-54 drops to a zero price for quantities above the extended reserve requirement. The price for reserve quantities less than the reserve requirement is $850 per MWh, and the price for reserve quantities above the reserve requirement to 190 MW above the reserve requirement is $300 per MWh.

130 *See, e.g.,* Scarcity and Shortage Pricing, Offer Mitigation and Offer Caps Workshop, Docket No. AD14-14-000, Transcript 29:21-30:14 (Oct. 28, 2014).

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



Nesting

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

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

Energy and Reserve Price Caps

Table 3-85 shows six example scenarios, under the current ORDCs, with combinations of energy offers, reserve shortage penalty factors and transmission constraint penalty factors that can add up to produce high LMPs at sample pnodes in the MAD Reserve Subzone and outside the MAD Reserve Subzone.

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

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

In scenario D, with a $1,000 per MWh offer price for the marginal unit for energy, violation of four reserve penalty factors only triggers SMP capping if the marginal unit for energy can serve the MAD reserve requirement. Scenario E and F show that LMPs can exceed $3,700 per MWh if there is a violated transmission constraint that is not exacerbated by an increase in load at the load weighted reference pricing node, which determines the SMP.[131]

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

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

Table 3-85 Real-time additive penalty factors under reserve shortage and transmission constraint violations: Status Quo

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

Circuit Breaker

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

Some of the circuit breaker proposals made in the stakeholder process would have applied during Elliott. The PJM load-weighted average LMP was greater than $1,000 per MWh for a 24 hour period. Of the hours when LMP was greater than $1,000 per MWh, only one hour on December 24 reached that level as a result of high fuel prices. In all other hours, administrative components of LMP set prices above $1,000 per MWh. The MMU proposes that only the administrative components of LMP be capped. Administrative components include ORDC penalty factors, transmission constraint penalty factors, and the maximum demand response strike price. Capping administrative components would prevent arbitrarily high prices while ensuring that the actual costs of meeting demand are included in prices.

Operator Actions

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

Locational Reserve Requirements

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

Shortage Pricing During Synchronized Reserve Events

Synchronized reserves are deployed when PJM declares a synchronized reserve event, also known as a spinning event. Currently, spinning events are triggered by an all call message to the system requesting all online generation units to increase their energy output. This deployment mechanism is used regardless of the actual MW needed to recover the Area Control Error (ACE) to zero or to the pre-event levels. Generally, the cause of the spinning event is a unit trip. Occasionally, PJM also declares spinning events to recover ACE when generators do not follow dispatch instructions to increase output. The response solicited through the all call message during a spinning event is much greater than the MW lost and MW needed to recover the ACE. This results in an overshoot of the ACE to positive values beyond the target range. There is currently no mechanism for PJM to selectively load synchronized reserves in proportion to the MW needed to recover ACE to zero or the pre-event levels, even though the PJM market rules allow PJM to load a proportion of reserves. While the all call message signals resources to increase their output, the approved SCED cases are solved with the reserve requirement intact, which dispatches the system to meet the load and reserve requirements ten to fourteen minutes into the future. This results in a discrepancy between the operational need during a spinning event, and the RT SCED solutions. PJM's instruction to generators is to ignore the dispatch signals sent by RT SCED, and instead continue to ramp their units up until the spin event ends.

Under the reserve market enhancements that began October 1, 2022, all synchronized reserves are treated as a uniform product and paid the market clearing price for synchronized reserves. All synchronized reserves are also assessed a penalty for nonperformance during the synchronized reserve events. Deployment of reserves during synchronized reserve events will be most efficient if the resources that are deployed and are subject to performance evaluation for their response are the resources that are committed as synchronized reserves. However, under PJM's proposed Intelligent Reserve Deployment (IRD) approach, PJM would rely on units that do not have a reserve commitment, while unnecessarily holding back committed and compensated reserve units during a spin event.[132] This is because the IRD approach is just a SCED solution based on: load increased by a predetermined amount; inflexible synchronized reserves converted to energy production; and maintaining the reserve requirement. The result is that inflexible synchronized reserves are converted to energy production, while flexible resources are held as reserves to meet the reserve requirement instead of responding to the spin event. Since PJM proposes penalties for lack of response during spin events for cleared and dispatched reserves, this results in inflexible synchronized reserve resources potentially being subject to penalties disproportionately, while flexible synchronized reserves may or may not be dispatched, and consequently may not be not subject to penalties. The IRD mechanism also creates a reliability risk since it relies on resources not committed as reserves to increase their output to recover ACE during a spin event, and these resources are not subject to a penalty for nonperformance. For these reasons, FERC rejected PJM's IRD proposal on August 15, 2022.[133]

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

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

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

Reserve Shortages in 2023

Reserve Shortage in Real-Time SCED

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

Until June 2, 2021, PJM generally solved one RT SCED case with three solutions per case, for each five minute target time.[134] [135] On June 3, 2021, PJM updated RT SCED to solve two additional scenarios, or a total of five solutions per case. In 2021, the frequency with which RT SCED solutions were approved increased to one solution per five minute interval. This approval frequency increased the proportion of approved SCED solutions that are reflected in LMPs. However, the process of selecting the SCED solution to approve, among the solutions available to PJM operators, is subjective and is not based on clearly defined criteria. The criteria are especially important when only some of the SCED solutions reflect shortage pricing, and the rest of the solutions do not.

The MMU analyzed the target times for which one or more RT SCED case solutions indicated a shortage of one or more reserve products. Table 3-86 shows, for each month of 2022 and the first three months of 2023, the total number of target times, the number of target times for which at least one RT SCED solution showed a shortage of reserves, the number of target times for which more than one RT SCED solution showed a shortage of reserves, and the number of five minute pricing intervals for which the LPC solution showed a shortage of reserves. Each execution of RT SCED produces five solutions, using five different levels of load bias Table 3-86 shows that, in the first three months of 2023, 351 target times, or 1.4 percent of all five minute target times, had at least one RT SCED solution showing a shortage of reserves, and 101 target times, or 0.4 percent of all five minute target times, had more than one RT SCED solution showing a shortage of reserves. In 2022, there were 9,026 target times, or 8.6 percent of all five minute target times, that had at least one RT SCED solution showing a shortage of reserves, and 2,766 target times, or 2.6 percent of all five minute target times, that had more than one RT SCED solution showing a shortage of reserves.

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

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

Table 3-86 Real-time monthly five minute SCED target times and pricing intervals with shortage: January 2022 through March 2023

Year, Month	Number of Five Minute Intervals	Number of Target Times With At Least One SCED Solution Short of Reserves	Percent Target Times With At Least One SCED Solution Short of Reserves	Number of Target Times With Multiple SCED Solutions Short of Reserves	Percent Target Times With Multiple SCED Solutions Short of Reserves	Number of Five Minute Intervals With Shortage Prices in LPC	Percent RT SCED Target Times With Reserve Shortage With Shortage Prices in LPC
2022 Jan	8,928	904	10.1%	276	3.1%	14	1.5%
2022 Feb	8,064	544	6.7%	153	1.9%	0	0.0%
2022 Mar	8,916	1,306	14.6%	381	4.3%	5	0.4%
2022 Apr	8,640	1,114	12.9%	343	4.0%	3	0.3%
2022 May	8,928	1,008	11.3%	265	3.0%	1	0.1%
2022 Jun	8,640	714	8.3%	170	2.0%	38	5.3%
2022 Jul	8,928	785	8.8%	223	2.5%	1	0.1%
2022 Aug	8,928	927	10.4%	263	2.9%	0	0.0%
2022 Sep	8,640	731	8.5%	187	2.2%	0	0.0%
2022 Oct	8,928	399	4.5%	151	1.7%	1	0.3%
2022 Nov	8,652	138	1.6%	46	0.5%	0	0.0%
2022 Dec	8,928	456	5.1%	308	3.4%	207	45.4%
2022 Total	105,120	9,026	8.6%	2,766	2.6%	270	3.0%
2023 Jan	8,928	187	2.1%	63	0.7%	3	1.6%
2023 Feb	8,064	89	1.1%	16	0.2%	0	0.0%
2023 Mar	8,916	75	0.8%	22	0.2%	0	0.0%
2023 Total	25,908	351	1.4%	101	0.4%	3	0.9%

In 2023, there were 3 five minute intervals with shortage pricing, while there were 101 five minute target times for which multiple RT SCED solutions showed a shortage of reserves. In 2022, there were 270 five minute intervals with shortage pricing, while 2,766 five minute target times for which multiple RT SCED solutions showed a shortage of reserves. Clear criteria for approval of shortage cases are needed.

The PJM Real-Time Energy Market produces an efficient outcome only when prices are allowed to reflect the fundamental supply and demand conditions in the market in real time. While it is appropriate for operators to ensure that cases use data that reflect the actual state of the system, it is essential that operator discretion not extend beyond what is necessary and that operator discretion not prevent shortage pricing when there are shortage conditions or implement shortage pricing when there are no shortage conditions. This is a critical issue now that PJM settles all real-time energy transactions on a five minute basis using the prices calculated by LPC. The pattern of shortage case approvals in Table 3-86 indicates that PJM operators consider factors other than RT SCED and LPC results when deciding whether to approve shortage cases. After a 5.3 percent approval rate in June 2022, the approval rate dropped to close to zero percent until December 2022 when it rose to 45.4 percent. The MMU recommends that PJM define clear criteria for operator approval of RT SCED cases, including shortage cases that are used to send dispatch signals to resources, and for pricing, to minimize discretion. A rule based approach is essential for defining how LMPs are determined so that all market participants can be confident that energy market pricing is efficient.

Shortage Pricing Intervals in LPC

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

There were three five minute intervals with shortage pricing in the first three months of 2023, compared to 19 intervals in the first three months of 2022.

PJM implemented fast start pricing on September 1, 2021. This resulted in differences in reserve shortages between the dispatch run and the pricing run in 2023. In the first three months of 2023, there were three five minute intervals with shortage pricing in the pricing run, and three intervals with shortage in the dispatch run.

Table 3-87 shows the extended synchronized reserve requirement, the total synchronized reserves, the synchronized reserve shortage, and the synchronized reserve clearing prices for the RTO Reserve Zone during the one interval with shortage pricing in the pricing run due to synchronized reserve shortage in the first three months of 2023. Table 3-87 shows that the one interval also had a synchronized reserve shortage for the RTO Reserve Zone in the dispatch run.

Table 3-88 shows the extended synchronized reserve requirement, the total synchronized reserves, the synchronized reserve shortage, and the synchronized reserve clearing prices for the MAD Reserve Subzone during the one interval with shortage pricing in the pricing run due to synchronized reserve shortage in the first three months of 2023. Table 3-88 shows that the one interval had a synchronized reserve shortage for the MAD Subzone in both the dispatch run and pricing run.

Table 3-89 shows the extended primary reserve requirement, the total primary reserves, the primary reserve shortage, and the primary reserve clearing prices for the RTO Reserve Zone during the three intervals with shortage pricing in the pricing run due to primary reserve shortage in the first three months of 2023. Table 3-89 shows that all three intervals were short of primary reserves in the pricing run and the dispatch run.

Table 3-90 shows the extended primary reserve requirement, the total primary reserves, the primary reserve shortage, and the primary reserve clearing prices for the MAD Reserve Subzone during the three intervals with shortage pricing in the pricing run due to primary reserve shortage in the first three months of 2023. Table 3-90 shows that all three of the intervals were short of primary reserves in both the dispatch run and the pricing run, and that two of the intervals had different capped prices in the dispatch and pricing runs.

PJM enforces an RTO wide reserve requirement and a supplemental reserve requirement for the MAD region. The MAD Reserve Subzone is inside the RTO Reserve Zone. Resources located in the MAD Reserve Subzone can simultaneously satisfy the synchronized reserve requirement of the RTO Reserve Zone and the synchronized reserve requirement of the MAD Reserve Subzone. Resources located outside the MAD Reserve Subzone can satisfy the synchronized reserve requirement of the RTO Reserve Zone, and subject to transfer limits defined by transmission constraints, satisfy the reserve requirement of the MAD Subzone. The synchronized reserve clearing price of the RTO Reserve Zone is set by the shadow price of the binding reserve requirement constraint of the RTO Reserve Zone.[136] The synchronized reserve clearing price of the MAD Reserve Subzone is set by the sum of the shadow prices of the binding reserve requirement constraint of the RTO Reserve Zone and the shadow price of the binding reserve requirement constraint of the MAD Reserve Subzone.

Table 3-87 Real-time RTO synchronized reserve shortage intervals: January through March, 2023

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

136 If the reserve requirement cannot be met by the resources located within the reserve zone, the shadow price of the reserve requirement is set by the applicable operating reserve demand curve.

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

Table 3-88 Real-time MAD synchronized reserve shortage intervals: January through March, 2023

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

Table 3-89 Real-time RTO primary reserve shortage intervals: January through March, 2023

	Pricing Run					Dispatch Run				
Interval (EPT)	RTO Extended Primary Reserve Requirement (MW)	Total RTO Primary Reserves (MW)	RTO Primary Reserve Shortage (MW)	Uncapped RTO Primary Reserve Clearing Price ($/MWh)	Capped RTO Primary Reserve Clearing Price ($/MWh)	RTO Extended Primary Reserve Requirement (MW)	Total RTO Primary Reserves (MW)	RTO Primary Reserve Shortage (MW)	Uncapped RTO Primary Reserve Clearing Price ($/MWh)	Capped RTO Primary Reserve Clearing Price ($/MWh)
10-Jan-23 07:10	2,695.0	2,505.0	190.0	$647.40	$647.40	2,695.0	2,505.0	190.0	$647.40	$647.40
10-Jan-23 07:15	2,696.5	1,935.0	761.5	$850.00	$850.00	2,696.5	1,935.0	761.5	$850.00	$850.00
10-Jan-23 07:20	2,695.0	2,375.1	319.9	$850.00	$850.00	2,695.0	2,375.1	319.9	$850.00	$850.00

Table 3-90 Real-time MAD primary reserve shortage intervals: January through March, 2023

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

The PJM tariff caps the MCP for primary reserves at one and a half times the nonsynchronized reserve penalty factor for each zone or subzone, and caps the MCP for synchronized reserves at the sum of the penalty factor for synchronized reserve and the penalty factor for nonsynchronized reserve, but the PJM tariff does not explicitly specify a cap on the system marginal price.[137] The system marginal price cap should be included in the PJM tariff and Operating Agreement.

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

System Marginal Price Cap

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

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

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

Table 3-91 shows number of five minute intervals in the real time market where the SMP was capped for each year since 2019. In the first three months of 2023, there was one five minute interval in the real time market where the SMP was capped.

Table 3-91 Number of five minute intervals with capped SMP: January 2019 through March 2023

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

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

Accuracy of Reserve Measurement

The definition of a shortage of synchronized and primary reserves is based on the measured and estimated levels of load, generation, interchange, demand response, and reserves from the real-time SCED software. The definition of such shortage also includes discretionary operator inputs to the ASO (Ancillary Service Optimizer) or RT SCED software, such as operator load bias. For shortage pricing to be accurate, there must be accurate measurement of real-time reserves. That does not appear to be the case at present in PJM, but there does not appear to be any reason that PJM cannot accurately measure reserves. Without accurate measurement of reserves on a minute by minute basis, system operators cannot know with certainty that there is a shortage condition and a reliable trigger for five minute shortage pricing does not exist. The benefits of five minute shortage pricing are based on the assumption that a shortage can be precisely and transparently defined.[138] PJM cannot accurately measure or price reserves due to the inaccuracy of its generator models. PJM's commitment and dispatch models rely on generator data to properly commit and dispatch generators. Generator data includes offers and parameters. When the models do not properly account for the different generator characteristics, both PJM dispatchers and generators have to make

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

simplifications and assumptions using the tools available. Most of these actions taken by generators and by PJM dispatchers are not transparent. PJM manuals do not provide clarity regarding what actions generators can take when the PJM models and tools do not reflect their operational characteristics and PJM manuals do not provide sufficient clarity regarding the actions PJM dispatchers can take when generators do not follow dispatch.

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

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

Competitive Assessment

Market Structure

Market Concentration

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

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

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

FERC's Merger Policy Statement defines levels of concentration by HHI level. The market is unconcentrated if the market HHI is below 1000, the HHI if there were 10 firms with equal market shares. The market is moderately concentrated if the market HHI is from 1000 to 1800. The market is highly concentrated if the market HHI is greater than 1800, the HHI if there were between five and six firms with equal market shares.[139]

When transmission constraints exist, local markets are created in which ownership is typically significantly more concentrated than the overall energy market. PJM offer capping rules that limit the exercise of local market power were generally effective in preventing the exercise of market power in the first three months of 2023, although there are issues with the application of market power mitigation for resources whose owners fail the TPS test that permit local market power to be exercised even when mitigation rules are applied. These issues include the lack of a method for consistently determining the cheaper of the cost and price schedules and the lack of rules requiring that cost-based offers equal short run marginal costs.

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

PJM HHI Results

Hourly HHIs indicate that by FERC standards, the PJM energy market in the first three months of 2023 was unconcentrated on average (Table 3-92).[140] The fact that the average HHI and the maximum hourly HHI are in the unconcentrated range does not mean that the aggregate market was competitive in all hours. It is possible to have pivotal suppliers in the aggregate market even when the HHI level does not indicate a highly concentrated market structure. Given the low responsiveness of consumers to prices (inelastic demand), it is possible to have high markup even when HHI is low. It is possible to have an exercise of market power even when the HHI level does not indicate a highly concentrated market structure.

Table 3-92 Real-time hourly aggregate energy market HHI: January through March, 2022 and 2023

HHI Statistic	Hourly Market HHI (Jan-Mar 2022)	Hourly Market HHI (Jan-Mar 2023)
Average	683	677
Minimum	581	575
Maximum	927	921
Highest market share (One hour)	25%	24%
Average of the highest hourly market share	18%	18%
# Hours	2,159	2,159
# Hours HHI > 1800	0	0
% Hours HHI > 1800	0%	0%

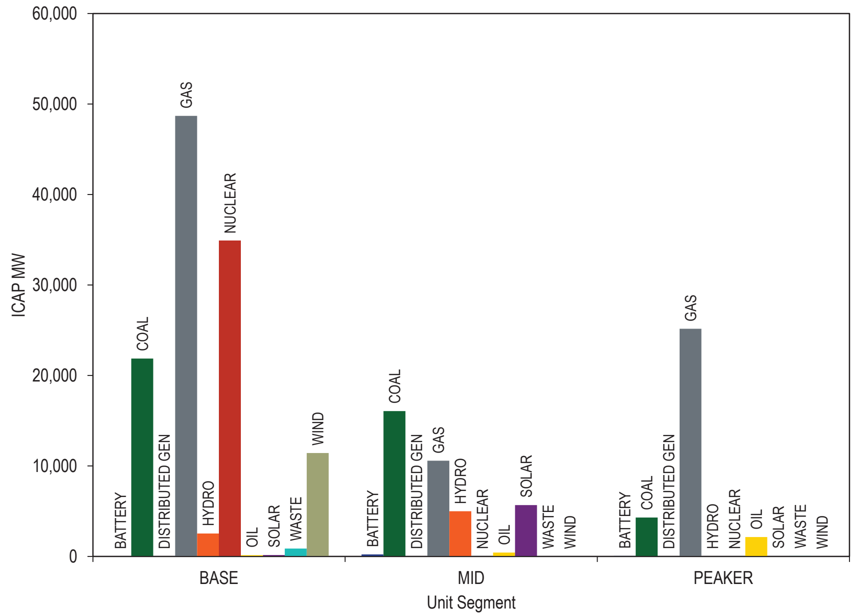
Table 3-93 includes HHI values by supply curve segment, including base, intermediate and peaking plants in the first three months of 2022 and 2023. On average, ownership in the baseload segment was unconcentrated, in the intermediate segment was moderately concentrated, and in the peaking segment was highly concentrated.[141] High concentration levels, particularly in the peaking segment, increase the probability that a generation owner will be pivotal in the aggregate market.

Table 3-93 Real-time hourly energy market HHI by generation segment: January through March, 2022 and 2023

	2022 (Jan-Mar)			2023 (Jan-Mar)		
	Minimum	Average	Maximum	Minimum	Average	Maximum
Base	622	717	941	577	702	974
Intermediate	719	1421	7346	687	1696	6553
Peak	802	6698	10000	889	6278	10000

Figure 3-55 shows the total installed capacity (ICAP) MW of units in the baseload, intermediate and peaking segments by fuel source in the first three months of 2023.[142]

Figure 3-55 Real-time ICAP distribution by fuel and segment: January through March, 2023[143]



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

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

142 The installed capacity (ICAP) used for wind and solar units here is their nameplate capacity in MW. In PJM's Capacity Market, the ICAP value of wind and solar units is derated from the nameplate capacity to reflect their effective load carrying capability.

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

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

Figure 3-56 Real-time annual gas and coal unit segment classification: January through March, 2013 through 2023

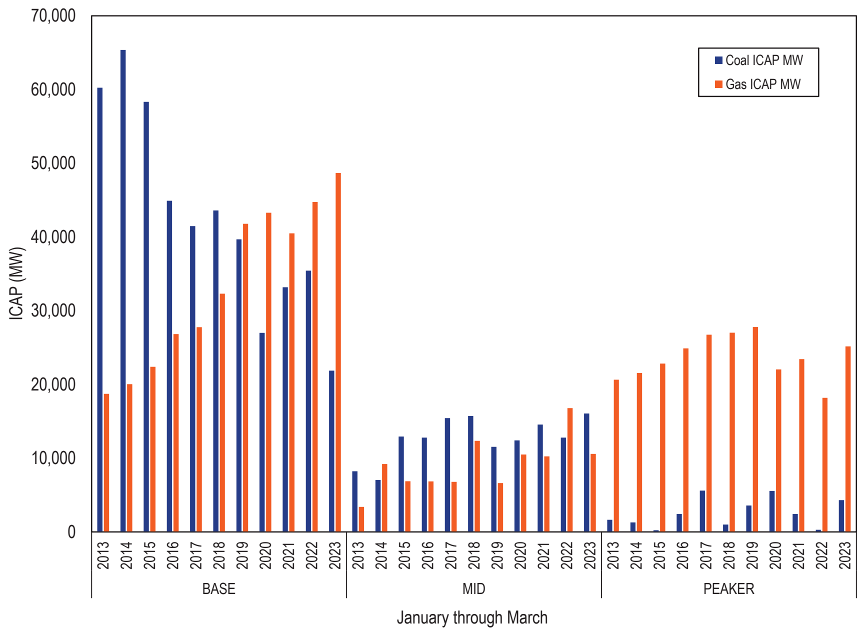
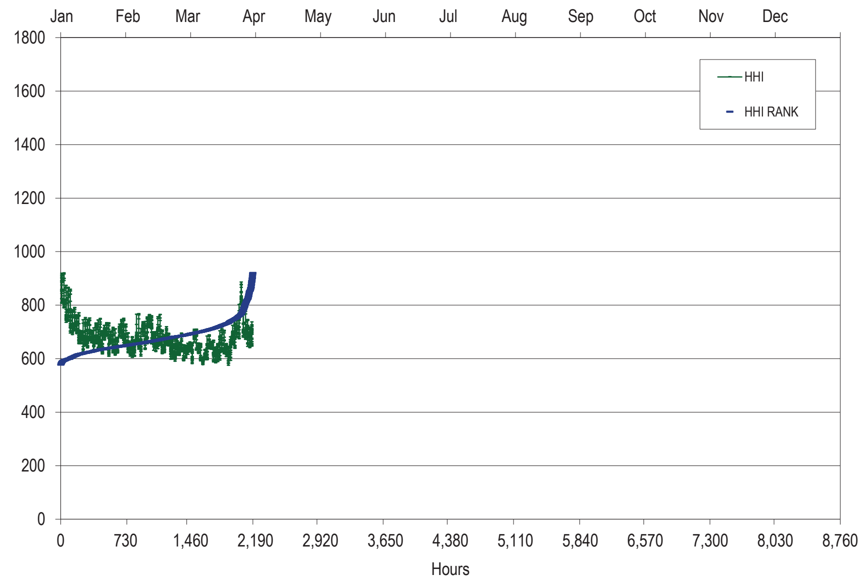


Figure 3-57 presents the hourly HHI values in chronological order and an HHI duration curve for the first three months of 2023.

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



Market Based Rates

Participation in the PJM market using offers that exceed costs requires market based rate authority approved by FERC.[144] FERC reviews the market based rate authority of PJM market sellers on a triennial schedule to ensure that market sellers do not have market power or that market power is appropriately mitigated. The entire PJM region is included in the Northeast Region for purposes of the triennial review schedule. Triennial filings by utilities with market based rates authorizations must include a market power analysis or a statement that market power has been adequately mitigated under the PJM market rules. Based on Order No. 861, sellers may, in lieu of filing a market power analysis, rely on a rebuttable presumption that market monitoring

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

and market power mitigation are sufficient to ensure competitive market outcomes.[145]

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

The most recent triennial review filings for nontransmission owning utilities in PJM were filed in June 2020. The applicable study period for the June 2020 filings, ran from December 1, 2017, to November 30, 2018. Triennial review filings for transmission owners in PJM were filed in December 2022. The applicable study period for the December 2022 filings ran from December 1, 2020, to November 30, 2021. The new triennial review filings for nontransmission owning utilities in PJM will be due in June 2023. The applicable study period for the June 2023 filings runs from December 1, 2020, to November 30, 2021.

The MMU has recommended since 2015 that changes to the offer capping process for the energy market are needed to ensure effective market power mitigation of units that fail the TPS test. With these results and the supporting evidence, the MMU challenged the rebuttable presumption of sufficient market power mitigation for the June 2020 and December 2022 triennial review filings by generating unit owners in PJM. The MMU recommended that generators should not be relying on PJM market power mitigation to ensure competitive market outcomes until improvements are made to the offer capping processes in the energy and capacity markets so that suppliers cannot exercise market power.[146] In 2021, FERC issued orders requiring review of the adequacy of the market power mitigation rules and their implementation in the capacity and energy markets.[147] [148] FERC addressed the capacity market Market Seller Offer cap later in 2021.[149]

Merger Reviews

FERC reviews proposed dispositions, consolidations, acquisitions, and changes in control of jurisdictional generating units and transmission facilities under section 203 of the Federal Power Act to determine whether such transactions are "consistent with the public interest."[150] [151]

FERC applies tests set forth in the 1996 Merger Policy Statement.[152] [153] The 1996 Merger Policy Statement provides for review of jurisdictional transactions based on "(1) the effect on competition; (2) the effect on rates; and (3) the effect on regulation." FERC adopted the 1992 Department of Justice Guidelines and the Federal Trade Commission Horizontal Merger Guideline (1992 Guidelines) to evaluate the effect on competition. FERC continues to use the 1992 Guidelines even after the Department of Justice modified its guidelines in 2010.[154] Following the 1992 Guidelines, FERC applies a five step framework, which includes: defining the market; analyzing market concentration; analyzing mitigative effects of new entry; assessing efficiency gains; and assessing viability of the parties without a merger. FERC also evaluates a Competitive Analysis Screen.

The MMU reviews proposed mergers based on analysis of the impact of the merger or acquisition on market power given actual market conditions. The analysis includes use of the three pivotal supplier test results in the real-time energy market. The MMU's review ensures that mergers are evaluated based on their impact on local market power in the PJM energy market using actual observed market conditions, actual binding constraints and actual congestion results. This is in contrast to the typical merger filing that uses predefined

145 *Refinements to Horizontal Market Power Analysis for Sellers in Certain Regional Transmission Organization and Independent System Operator Markets*, Order No. 861, 168 FERC ¶ 61,040 (2019) ("Order No. 861").
146 See Protest of the Independent Market Monitor for PJM, Docket No. ER10-1556 et al. (August 28, 2020); Comments of the Independent Market Monitor for PJM, Docket No. ER10-1618-018 et al. (February 13, 2023).
147 See 175 FERC ¶ 61,231 (2021).
148 See 174 FERC ¶ 61,212 (2021).
149 See 176 FERC ¶ 61,137 (2021), *reh'g denied*, 178 FERC ¶ 61,121 (2022), *appeal pending*.
150 18 U.S.C. § 824b.
151 In February 2019, in response to 2017 amendments to Section 203 of the Federal Power Act, the Commission issued Order No. 855, implementing a $10,000,000 minimum value for transactions requiring the Commission's review. See 166 FERC ¶ 61,120 (2019)
152 See Order No. 592, FERC Stats. & Regs. ¶ 31,044 (1996) (1996 Merger Policy Statement), *reconsideration denied*, Order No. 592-A, 79 FERC ¶ 61,321 (1997). See also FPA Section 203 Supplemental Policy Statement, FERC Stats. & Regs. ¶ 31,253 (2007), *order on clarification and reconsideration*, 122 FERC ¶ 61,157 (2008).
153 FERC has an open but inactive docket where the guidelines are under review. See 156 FERC ¶ 61,214 (2016); FERC Docket No. RM16-21-000.
154 See 138 FERC ¶ 61,109 (2012).

local markets based on historical conditions that no longer exist rather than the actual local markets based on current and potential market conditions. The MMU files comments including such analyses.[155] The MMU has proposed that FERC adopt this approach when evaluating mergers in PJM.[156] FERC has considered the MMU's analysis in reviewing mergers but continues to apply a definition of markets based on an outdated and static definition of relevant markets in PJM.[157]

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

The MMU also reviews transactions that involve ownership changes of PJM generation resources that are submitted to the Commission pursuant to section 203 of the Federal Power Act. Table 3-94 shows transactions that involved entire resources that were completed in the first three months of 2023, as reported to the Commission. Table 3-95 shows transactions that involved transfers of partial unit ownership that were completed in the first three months of 2023, as reported to the Commission.[158]

Table 3-94 Completed transfers of entire resources: January through March, 2023

Generator or Generation Owner Name	From	To	Transaction Completion Date	Docket
Summersville Hydro	Hull Street Energy, LLC	LS Power Development, LLC	January 5, 2023	EC23-22
South Jersey Industries, Inc	South Jersey Industries, Inc	IIF US Holding 2	February 7, 2023	EC22-60
Energy Power Investment Company	North American Sustainable Energy Fund, L.P. and Energy Power Partners Fund I, L.P.	NextEra Energy, Inc	March 21, 2023	EC23-36
Shawville Power, LLC	Public Service Enterprise Group Incorporated	GenOn Holdings, Inc.	March 28, 2023	EC23-46

Table 3-95 Completed transfers of partial ownership of resources: January through March, 2023

Generator or Generation Owner Name	From	To	Transaction Completion Date	Docket
Roth Rock Wind Farm, LLC (20%)	Acek Energías Renovables, S.L. and Clear Wind Eólica, S.L.	ORIX Corporation	February 14, 2023	EC23-37
Jackson Generation, LLC (49%)	Jackson Capital, LLC	Gulf Energy, USA, LLC	February 27, 2023	EC23-3
RWE Porfolio (9.1%)	RWE Aktiengesellschaf	Qatar Holding LLC	March 15, 2023	EC23-35

The MMU has also reached agreements to mitigate market power in cases where market power concerns have been identified.[159] Such mitigation is designed to mitigate behavior over the long term, in addition to or instead of structural mitigation in the form of asset divestiture requirements.

155 See, e.g., Comments of the Independent Market Monitor for PJM, FERC Docket No. EC14-141-000 (Nov. 10, 2014); Comments of the Independent Market Monitor for PJM, FERC Docket No. EC14-96-000 (July 21, 2014) Comments of the Independent Market Monitor for PJM, FERC Docket No. EC11-83-000 (July 21, 2011); Comments of the Independent Market Monitor for PJM, FERC Docket No. EC14-14 (Dec. 9, 2013); Comments of the Independent Market Monitor for PJM, FERC Docket No. EC14-112-000 (Sept. 15, 2014); Comments of the Independent Market Monitor for PJM, FERC Docket No. EC20-49 (June 1, 2020).

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

157 See *Dynegy Inc., et al.*, 150 FERC ¶ 61, 231 (2015); *Exelon Corporation, Constellation Energy Group, Inc.*, 138 FERC ¶ 61,167 (2012); *NRG Energy Holdings, Inc., Edison Mission Energy*, 146 FERC ¶ 61,196 (2014); *see also Analysis of Horizontal Market Power under the Federal Power Act*, 138 FERC ¶ 61,109 (2012).

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

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

Aggregate Market Pivotal Supplier Results

Notwithstanding the HHI level, a supplier may have the ability to raise energy market prices. If reliably meeting the PJM system load requires energy from a single supplier, that supplier is singly pivotal and has monopoly power in the aggregate energy market. If a small number of suppliers are jointly required to meet load, those suppliers are jointly pivotal and have oligopoly power. The number of pivotal suppliers in the energy market is a more precise measure of structural market power than the HHI. The HHI is not a definitive measure of structural market power. The identification of jointly pivotal suppliers as a source of market power does not require an assumption that the suppliers collude. There are multiple mechanisms that would permit the exercise of market power when there are limited suppliers providing relief to a constraint. FERC Order No. 697 also recognizes this explicitly in the discussion of HHI and pivotal suppliers.[160] FERC's definition of highly concentrated markets, based on an HHI greater than 1800, includes between five and six owners with equal market shares.

The current market power mitigation rules for the PJM energy market rely on the assumption that the aggregate market includes sufficient competing sellers to ensure competitive market outcomes. With sufficient competition, any attempt to economically or physically withhold generation would not result in higher market prices, because another supplier would replace the generation at a similar price. This assumption requires that the total demand for energy can be met without the supply from any individual supplier or without the supply from a small group of suppliers. This assumption is not always correct, as demonstrated by these results. There are pivotal suppliers in the aggregate energy market.

The existing market power mitigation measures do not address aggregate market power.[161] Aggregate market power should be mitigated in the PJM day-ahead and real-time markets when the three pivotal supplier test is failed.

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

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

Day-Ahead Energy Market Aggregate Pivotal Suppliers

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

Figure 3-58 shows the number of days in 2022 and the first three months of 2023 with one aggregate pivotal supplier, two aggregate jointly pivotal suppliers, and three aggregate jointly pivotal suppliers for the day-ahead energy market. Multiple suppliers were singly pivotal on the summer peak days of 2022. One supplier was singly pivotal on June 15 and 16, 2022, and on December 25, 2022. Two suppliers were jointly pivotal on 20 days in the first three months of 2022 and zero days in the first three months of 2023. Three suppliers were jointly pivotal on 66 days in the first three months of 2022 and 16 days in the first three months of 2023, despite average HHIs at persistently unconcentrated levels. In 2022, the highest levels of aggregate market power occurred in the third quarter, PJM's summer peak load season. Outside the summer months, the frequency of pivotal suppliers increased on high demand days in January and December 2022.

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

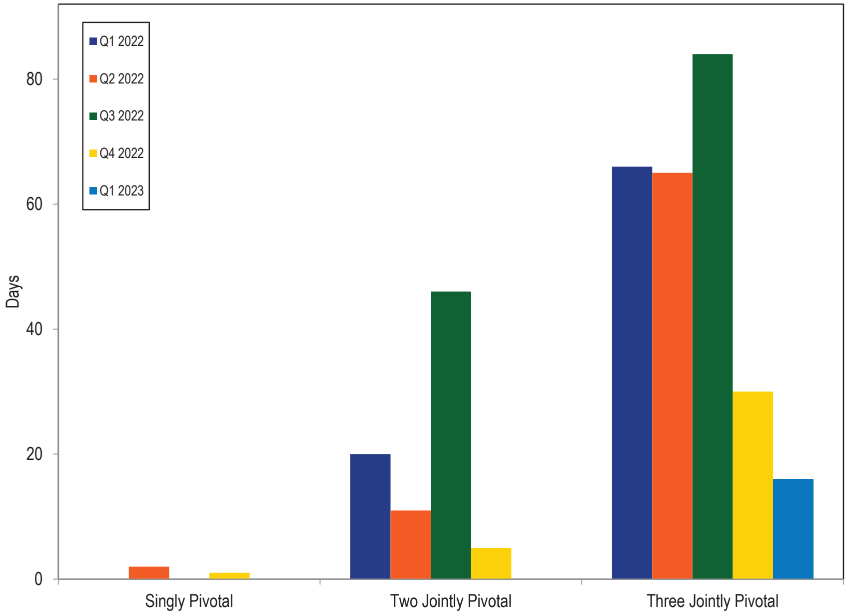


Table 3-96 provides the frequency with which each of the top 10 pivotal suppliers was singly or jointly pivotal for the day-ahead energy market in the first three months of 2023. All of the top 10 suppliers were one of three pivotal suppliers on at least 3 days in the first three months of 2023 (3.3 percent of the days).

Table 3-96 Day-ahead market pivotal supplier frequency: January through March, 2023

Pivotal Supplier Rank	Days Singly Pivotal	Percent of Days	Days Jointly Pivotal with One Other Supplier	Percent of Days	Days Jointly Pivotal with Two Other Suppliers	Percent of Days
1	0	0.0%	0	0.0%	16	17.8%
2	0	0.0%	0	0.0%	16	17.8%
3	0	0.0%	0	0.0%	15	16.7%
4	0	0.0%	0	0.0%	14	15.6%
5	0	0.0%	0	0.0%	12	13.3%
6	0	0.0%	0	0.0%	9	10.0%
7	0	0.0%	0	0.0%	7	7.8%
8	0	0.0%	0	0.0%	6	6.7%
9	0	0.0%	0	0.0%	4	4.4%
10	0	0.0%	0	0.0%	3	3.3%

Market Behavior

Local Market Power

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

The three pivotal supplier (TPS) test is the test for local market power in the energy market.[162] If the TPS test is failed, market power mitigation is applied by offer capping the resources of the owners who have been identified as having local market power. Offer capping is designed to set offers at competitive levels. Competitive offers are defined to be cost-based energy offers. In the PJM energy market, units are required to submit cost-based energy offers, defined by fuel cost policies, and have the option to submit market-based, also called price-based, offers. Units are committed and dispatched on price-

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

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

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

TPS Test Statistics for Local Market Power

The TPS test in the energy market defines whether one, two or three suppliers are jointly pivotal in a defined local market. The TPS test is applied when the system solution indicates that out of merit resources are needed to relieve a transmission constraint. The TPS test result for a constraint for a specific interval indicates whether a supplier failed or passed the test for that constraint for that interval. A failed test indicates that the resource owner has structural market power.

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

In the first three months of 2023 in the day-ahead energy market, the 500 kV system, nineteen zones, and PJM/MISO experienced congestion resulting from one or more constraints binding for 25 or more hours, or resulting from a binding interface constraint (Table 3-98).[163] Table 3-98 shows that the 500 kV system, nine zones and PJM/MISO experienced congestion resulting from one or more constraints binding for 25 or more hours or resulting from a binding interface constraint in every year from January through March, 2014 through 2023. Two zones did not experience congestion resulting from one or more constraints binding for 25 or more hours or resulting from any binding interface constraint in any year from January through March, 2014 through 2023.[164]

Table 3-97 Day-ahead congestion hours resulting from one or more constraints binding for 25 or more hours: January through March, 2014 through 2023

	(Jan - Mar)									
	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
500 kV System	10,847	4,543	2,146	2,167	2,041	1,514	1,867	353	946	214
ACEC	515	589	2,107	898	820	2,119	1,023	241	69	681
AEP	26,255	9,430	11,741	14,180	8,552	3,514	1,517	1,386	860	2,397
APS	5,970	2,083	2,888	3,018	1,068	813	916	1,099	904	668
ATSI	2,630	1,094	882	1,518	1,228	632	32	0	220	235
BGE	1,761	1,292	3,451	2,943	1,933	883	723	1,426	117	508
COMED	17,157	2,418	12,266	18,294	9,476	1,744	1,068	729	987	747
DAY	0	28	0	188	176	0	187	0	0	90
DEOK	5,870	1,586	3,642	1,465	1,045	245	0	253	142	282
DLCO	1,051	790	218	0	74	0	0	0	97	0
DOM	2,246	2,161	1,521	1,828	1,652	74	238	222	1,116	898
DPL	5,011	2,417	4,871	3,678	3,287	1,636	1,106	1,113	896	1,181
DUKE	0	0	0	0	0	0	0	0	0	0
DUQ	0	0	0	0	0	0	0	0	0	0
EKPC	0	0	1,216	283	133	0	0	0	0	26
EXT	616	1,117	0	440	0	0	0	0	0	0
JCPLC	2,992	1,341	1,969	1,372	728	69	0	0	0	904
MEC	1,131	304	845	1,473	1,945	1,052	291	318	482	732
PJM/MISO	10,819	7,098	4,955	7,429	7,279	3,650	1,952	1,532	3,828	2,175
PJM/NYISO	0	0	0	515	0	0	0	0	0	0
OVEC	0	0	0	0	0	0	736	0	66	600
PE	2,412	927	2,579	5,909	4,224	1,669	1,701	103	1,970	773
PECO	1,935	1,142	1,080	3,261	1,039	392	718	389	669	1,735
PEPCO	262	209	67	316	79	103	0	0	174	130
PPL	2,311	31	527	2,060	1,030	3,314	1,587	1,651	2,776	704

In the first three months of 2023 in the real-time energy market, the 500 kV system, nine zones, and PJM/MISO experienced congestion resulting from one or more constraints binding for 25 or more hours, or resulting from a binding interface constraint (Table 3-98).[165] Table 3-98 shows that the 500 kV system, five zones and PJM/MISO experienced congestion resulting from one or more constraints binding for 25 or more hours or resulting from a

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

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

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

binding interface constraint in every year from January through March, 2014 through 2023. Four zones did not experience congestion resulting from one or more constraints binding for 25 or more hours or resulting from any binding interface constraint in any year from January through March, 2014 through 2023.[166]

Table 3-98 Real-time congestion hours resulting from one or more constraints binding for 25 or more hours: January through March, 2014 through 2023

	(Jan - Mar)									
	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
500 kV System	1,805	734	306	157	357	519	1,151	705	747	26
ACEC	0	41	252	0	0	112	0	72	0	0
AEP	809	1,211	204	56	525	126	214	1,373	124	323
APS	309	345	72	0	0	30	181	996	82	0
ATSI	354	312	0	119	473	0	0	66	165	88
BGE	30	232	1,359	476	881	134	266	1,314	67	128
COMED	782	399	692	559	287	207	492	750	396	320
DAY	0	0	0	0	0	0	0	181	0	0
DEOK	34	0	0	0	25	0	0	176	46	0
DLCO	211	426	0	0	57	0	0	0	0	0
DOM	88	494	473	52	91	0	236	669	615	149
DPL	247	388	703	389	141	0	0	204	0	0
DUKE	0	0	0	0	0	0	0	0	0	0
DUQ	0	0	0	0	0	0	0	0	0	0
EKPC	0	0	0	0	45	0	0	0	0	0
EXT	0	0	0	348	0	0	51	0	0	0
JCPLC	44	79	0	0	0	0	0	0	0	0
MEC	34	72	0	0	367	92	162	326	51	103
PJM/MISO	2,827	1,547	1,197	1,302	1,296	1,318	918	2,453	2,726	1,291
PJM/NYISO	107	174	516	332	0	0	0	0	0	0
OVEC	0	0	0	0	0	0	0	0	0	0
PE	179	514	182	525	738	865	945	447	1,142	213
PECO	331	244	238	772	37	109	200	544	404	858
PEPCO	39	0	0	0	0	0	0	0	0	0
PPL	41	0	0	137	0	458	294	792	521	91
PSEG	978	1,610	60	0	125	202	0	938	463	38
REC	0	0	0	0	0	0	0	0	0	0

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

In the PJM Day-Ahead Energy Market, the TPS test is performed in PROBE, as part of the unit commitment process. Table 3-99 shows the average constraint relief required on the constraint, the average effective supply available to relieve the constraint, the average number of owners with available relief in the defined market and the average number of owners passing and failing the TPS test for the interface constraints in the PJM Day-Ahead Energy Market.

Table 3-99 Day-ahead three pivotal supplier test details for internal interface constraints: January through March, 2023

Constraint	Period	Number of Tests	Average Constraint Relief (MW)	Average Effective Supply (MW)	Average Number Owners	Average Number Owners Failing	Average Number Owners Passing
5004/5005	Peak	0	0	0	0	0	0
	Off Peak	1	246	191	19	19	0
AEP - DOM	Peak	18	421	230	13	9	4
	Off Peak	17	592	292	15	15	0
AP South	Peak	19	362	772	23	13	10
	Off Peak	15	702	1,385	26	20	6
Bedington - Black Oak	Peak	15	140	201	20	12	8
	Off Peak	10	221	203	23	20	3
East	Peak	0	0	0	0	0	0
	Off Peak	1	139	1,241	10	0	10

Table 3-100 shows the average constraint relief required on the constraint, the average effective supply available to relieve the constraint, the average number of owners with available relief in the defined market, whether the TPS test was applied, and the average number of owners passing and failing the TPS test. The TPS test was not applied for two of the 10 constraints that were binding for the most hours in the day-ahead energy market. In the day-ahead energy market, the TPS test evaluates each constraint that was binding for each hour during the operating day after the initial unit commitment run. The set of constraints that are binding in the unit commitment run, for which the TPS test is applied, is not necessarily the same as the set of constraints that bind in the final day-ahead energy market solution. This is because PJM's day-ahead market is solved in three stages, and the initial set of constraints is from the Resource Scheduling and Commitment (RSC) (unit commitment) stage while the final set of binding constraints is from the Scheduling Pricing and Dispatch (SPD) (unit dispatch) stage.[167] The PJM approach fails to apply the TPS test to market sellers that provide relief to constraints in the final dispatch solution, and therefore fails to mitigate such sellers for market power.

Table 3-100 shows that three of the top ten binding constraints in the day-ahead energy market were not tested for local market power in the first three months of 2023 (Ramapo, DOEx, and Mountain). The MMU recommends that PJM modify the process for applying the TPS test in the day-ahead energy market to ensure that all local markets created by binding constraints are tested for market power and to ensure that market sellers with market power are appropriately mitigated to their competitive offers.

Table 3-100 Day-ahead three pivotal supplier test details for top 10 congested constraints: January through March, 2023

Constraint	Period	Number of Tests	Average Constraint Relief (MW)	Average Effective Supply (MW)	Average Number Owners	Average Number Owners Passing	Average Number Owners Failing
Nottingham	Peak	705	314	414	28	13	15
	Off Peak	480	196	335	24	13	12
Sayreville - Sayreville	Peak	10	0	0	0	0	0
	Off Peak	8	0	0	0	0	0
Easton - Emuni	Peak	9	160	115	7	0	7
	Off Peak	4	102	107	6	0	6
Ramapo (ConEd) - S Mahwah (RECO)	Peak	0	0	0	0	0	0
	Off Peak	0	0	0	0	0	0
Gardners - Texas Eastern	Peak	367	16	7	1	0	1
	Off Peak	227	8	4	1	0	1
DoeX530	Peak	0	0	0	0	0	0
	Off Peak	0	0	0	0	0	0
Allen - R.P. Mone	Peak	92	22	36	6	0	6
	Off Peak	112	19	27	5	0	4
Weedman - Mahomet	Peak	79	123	85	6	0	6
	Off Peak	166	111	57	4	0	4
Monroe - Vineland	Peak	19	234	168	15	2	13
	Off Peak	4	293	207	15	2	13
Cumberland - Juniata	Peak	784	137	82	11	0	10
	Off Peak	305	88	56	7	0	7
Lenox - North Meshoppen	Peak	393	72	45	9	1	8
	Off Peak	274	69	33	7	1	6
Mountain	Peak	0	0	0	0	0	0
	Off Peak	0	0	0	0	0	0

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

The local market structure in the real-time energy market associated with each of the frequently binding constraints was analyzed using the three pivotal supplier results in the first three months of 2023.[168] While the real-time constraint hours include constraints that were binding in the five minute real-time dispatch solution (RT SCED), IT SCED, the software that performs the TPS test, may contain different binding constraints because IT SCED looks ahead to target times that are in the near future to solve for constraints that could be binding, using the load forecast for those times.[169] IT SCED solves for target times that occur at 15 minute time increments, unlike RT SCED that solves for every five minute time increment. The TPS statistics shown in this section present the data from the IT SCED TPS solution. Some IT SCED TPS solutions are used to commit units, while others are not. PJM operators have discretion in choosing which units to commit and which IT SCED results to use as the basis for the commitment and therefore which units are tested for market power using the TPS test. The results of the TPS test are shown for tests that could have resulted in offer capping and tests that resulted in offer capping.

Table 3-101 shows the average constraint relief required on the constraint, the average effective supply available to relieve the constraint, the average number of owners with available relief in the defined market and the average number of owners passing and failing for the interface constraints in the PJM Real-Time Energy Market. Table 3-102 shows the average constraint relief required on the constraint, the average effective supply available to relieve the constraint, the average number of owners with available relief in the defined market and the average number of owners passing and failing for the 10 constraints that were binding for the most hours in the PJM Real-Time Energy Market. Table 3-101 and Table 3-102 include analysis of all the tests for every target time where IT SCED determined that constraint relief was needed for each of the constraints shown. The same target time can be evaluated by multiple IT SCED cases at different look ahead times. Each 15 minute target time is

168 See the *MMU Technical Reference for PJM Markets*, p. 38 "Three Pivotal Supplier Test" for a more detailed explanation of the three pivotal supplier test. <http://www.monitoringanalytics.com/reports/Technical_References/references.shtml>.

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

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

Table 3-101 Real-time three pivotal supplier test details for internal interface constraints: January through March, 2023

Constraint	Period	Number of Tests	Average Constraint Relief (MW)	Average Effective Supply (MW)	Average Number Owners	Average Number Owners Passing	Average Number Owners Failing
AP South	Peak	220	510	754	14	2	12
	Off Peak	233	802	867	12	1	12
West	Peak	42	424	356	12	0	12
	Off Peak	9	218	282	7	0	7

Table 3-102 Real-time three pivotal supplier test details for top 10 congested constraints: January through March, 2023

Constraint	Period	Number of Tests	Average Constraint Relief (MW)	Average Effective Supply (MW)	Average Number Owners	Average Number Owners Passing	Average Number Owners Failing
Nottingham	Peak	17,693	96	145	11	2	9
	Off Peak	10,988	75	118	10	2	7
Weedman - Mahomet	Peak	4,191	19	4	1	0	1
	Off Peak	6,541	21	3	2	0	2
Turkey Hill - Mascoutah	Peak	604	20	13	3	0	3
	Off Peak	1,466	19	11	2	0	2
Lenox - North Meshoppen	Peak	2,234	17	34	3	0	3
	Off Peak	2,010	11	26	2	0	2
Graceton - Safe Harbor	Peak	1,689	77	108	12	4	8
	Off Peak	2,072	80	95	10	1	9
Mahomet - OCB	Peak	1,871	29	10	2	0	2
	Off Peak	1,485	28	11	2	0	2
Powerton - Towerline	Peak	1,505	13	24	1	0	1
	Off Peak	877	13	23	1	0	1
Tanners Creek - Dearborn	Peak	1,084	231	318	5	0	5
	Off Peak	2,516	170	251	4	0	4
Gardners - Texas Eastern	Peak	2,437	28	17	2	0	2
	Off Peak	2,397	24	15	2	0	2
Prest - Tibb	Peak	399	17	11	2	0	2
	Off Peak	566	23	11	2	0	2

The three pivotal supplier test is applied every time the IT SCED solution indicates that incremental relief is needed to relieve a transmission constraint. While every system solution that requires incremental relief to transmission constraints will result in a test, not all tested providers of effective supply are eligible for offer capping. Steam unit offers that are offer capped in the day-ahead energy market continue to be offer capped in the real-time energy market regardless of their inclusion in the TPS test in real time or the outcome of the TPS test in real time. Steam unit offers that are not offer capped in the day-ahead energy market continue to not be offer capped in the real-time energy market regardless of their inclusion in the TPS test in real time or the outcome of the TPS test in real time.[170] Offline units that are committed to provide relief for a transmission constraint, whose owners fail the TPS test, are committed on the cheaper of their cost or price-based offers. Beginning November 1, 2017, with the introduction of hourly offers and intraday offer updates, online units whose commitment is extended beyond the day-ahead or real-time commitment, whose owners fail the TPS test, are also switched to the cost-based offer if it is cheaper than the price-based offer.

Units committed in the day-ahead market often fail the TPS test in the real-time market when they are redispatched to provide relief to transmission constraints, even though they did not fail the TPS test in the day-ahead market. Day-ahead committed units are not evaluated for offer capping in real-time unless they update their cost-based offer. These units are able to set prices with a positive markup in the real-time market. Units that cleared the day-ahead market on their price based schedule were evaluated to identify the units whose offers were mitigated in real-time and the units that cleared on price offers in real-time despite failing the real-time TPS test. Table 3-103 shows that 2.3 percent of unit hours that cleared the day-ahead market on their price based offer were switched to cost in real-time. Table 3-103 shows that 6.8 percent of unit hours that cleared the day-ahead market on their price based offer cleared on their price based offer in real-time despite failing the real-time TPS test.

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

Table 3-103 Day-ahead units committed on price-based offers that cleared real-time: January through March, 2022 and 2023

	Day Ahead Price Based Unit Hours That Cleared Real-Time			Percent Day Ahead Price Based Unit Hours That Cleared Real-Time	
Year (Jan-Mar)	On Cost	On Price	On Price and Failed TPS Test	On Cost	On Price and Failed TPS Test
2022	6,957	624,989	78,228	1.0%	8.5%
2023	15,243	636,053	44,361	2.3%	6.8%

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

Table 3-104 and Table 3-105 provide, for the identified constraints, information on total tests applied, the subset of three pivotal supplier tests that could have resulted in offer capping and the portion of those tests that did result in offer capping in the real-time energy market. Tests where there was at least one offline unit or an online unit eligible for offer capping are considered tests that could have resulted in offer capping. PJM operators also manually commit units for reliability reasons other than providing relief to a binding constraint. Manual commitments are offer capped along with resources that fail the TPS test.

Table 3-104 Summary of real-time three pivotal supplier tests applied for internal interface constraints: January through March, 2023

Constraint	Period	Total Tests Applied	Total Tests that Could Have Resulted in Offer Capping	Percent Total Tests that Could Have Resulted in Offer Capping	Total Tests Resulted in Offer Capping	Percent Total Tests Resulted in Offer Capping	Tests Resulted in Offer Capping as Percent of Tests that Could Have Resulted in Offer Capping
AP South	Peak	220	220	100%	9	4%	4%
	Off Peak	233	233	100%	1	0%	0%
West	Peak	42	42	100%	0	0%	0%
	Off Peak	9	9	100%	0	0%	0%

Table 3-105 Summary of real-time three pivotal supplier tests applied for top 10 congested constraints: January through March, 2023

Constraint	Period	Total Tests Applied	Total Tests that Could Have Resulted in Offer Capping	Percent Total Tests that Could Have Resulted in Offer Capping	Total Tests Resulted in Offer Capping	Percent Total Tests Resulted in Offer Capping	Tests Resulted in Offer Capping as Percent of Tests that Could Have Resulted in Offer Capping
Nottingham	Peak	17,693	17,634	100%	101	1%	1%
	Off Peak	10,988	10,812	98%	88	1%	1%
Weedman - Mahomet	Peak	4,191	390	9%	0	0%	0%
	Off Peak	6,541	721	11%	0	0%	0%
Turkey Hill - Mascoutah	Peak	604	26	4%	0	0%	0%
	Off Peak	1,466	43	3%	0	0%	0%
Lenox - North Meshoppen	Peak	2,234	1,342	60%	0	0%	0%
	Off Peak	2,010	610	30%	0	0%	0%
Graceton - Safe Harbor	Peak	1,689	1,673	99%	12	1%	1%
	Off Peak	2,072	2,070	100%	8	0%	0%
Mahomet - OCB	Peak	1,871	320	17%	0	0%	0%
	Off Peak	1,485	436	29%	0	0%	0%
Powerton - Towerline	Peak	1,505	270	18%	0	0%	0%
	Off Peak	877	75	9%	0	0%	0%
Tanners Creek - Dearborn	Peak	1,084	853	79%	26	2%	3%
	Off Peak	2,516	1,891	75%	10	0%	1%
Gardners - Texas Eastern	Peak	2,437	1,134	47%	6	0%	1%
	Off Peak	2,397	1,389	58%	10	0%	1%
Prest - Tibb	Peak	399	0	0%	0	0%	NA
	Off Peak	566	0	0%	0	0%	NA

Offer Capping for Local Market Power

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

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

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

When an owner fails the TPS test, the units offered by the owner that are committed to provide relief are committed on the cheaper of cost-based or price-based offers. In the day-ahead energy market, PJM commits a unit on the schedule that results in the lower overall system production cost. Under the current approach, operating parameters are tied to the cost parameters (startup cost, no load cost, and incremental energy offer). The day-ahead energy market selects which schedule to use for a resource that failed the TPS test based on its objective of clearing resources to meet the total demand at the lowest bid production cost for the system over the 24 hour period. True least system production cost can be achieved using an approach in which operating parameters and offer parameters are independently evaluated.

In the real-time energy market, PJM uses a dispatch cost formula to compare price-based offers and cost-based offers to select the cheaper offer.[171]

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

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

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

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

171 See OA Schedule 1 § 6.4.1(g).

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

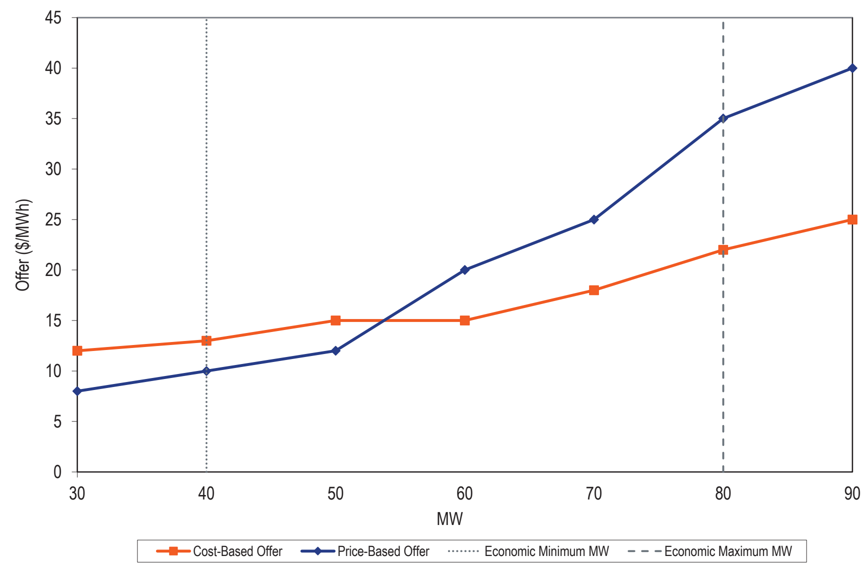


Table 3-106 shows the number and percent of unit schedule hours, by month, when unit offers included crossing curves in the PJM Day-Ahead and Real-Time Energy Markets in 2022. The analysis only includes units that offer both price-based and cost-based offers. Units in PJM are only required to submit cost-based offers, but they may elect to offer price-based offers.

Table 3-106 Units offered with crossing curves: January through March, 2023

	Day-Ahead			Real-Time		
2023	Number of Schedule Hours with Crossing Curves	Total Number of Cost Schedule Hours Offered by Price Based Units	Percent of Schedule Hours with Crossing Curves	Number of Schedule Hours with Crossing Curves	Total Number of Cost Schedule Hours Offered by Price Based Units	Percent of Schedule Hours with Crossing Curves
Jan	82,916	838,800	9.9%	67,737	777,827	8.7%
Feb	72,470	764,688	9.5%	59,552	713,752	8.3%
Mar	77,731	847,714	9.2%	64,000	737,532	8.7%
Total	233,117	2,451,202	9.5%	191,289	2,229,111	8.6%

Offering a different economic minimum MW level, different minimum run times, or different start up and notification times in the cost-based and price-based offers can also be used to evade mitigation. For example, a unit may have a price-based offer with a positive markup, but have a shorter minimum run time (MRT) in the price-based offer resulting in a lower dispatch cost for the price-based offer but setting prices at a level that includes a positive markup. Table 3-107 shows the number and percent of unit schedule hours when units offered lower minimum run times in price-based offers than in cost-based offers while having a positive markup in the price based offer.

Table 3-107 Units offered with lower minimum run time on price compared to cost and with positive markup: January through March, 2023

	Day-Ahead			Real-Time		
2023	Number of Schedule Hours with Lower Min Run Time in Price Compared to Cost	Total Number of Cost Schedule Hours Offered by Price Based Units	Percent of Schedule Hours with Lower Min Run Time in Price Compared to Cost	Number of Schedule Hours with Lower Min Run Time in Price Compared to Cost	Total Number of Cost Schedule Hours Offered by Price Based Units	Percent of Schedule Hours with Lower Min Run Time in Price Compared to Cost
Jan	10,896	838,800	1.3%	9,618	777,827	1.2%
Feb	3,480	764,688	0.5%	2,661	713,752	0.4%
Mar	2,972	847,714	0.4%	2,498	737,532	0.3%
Total	17,348	2,451,202	0.7%	14,777	2,229,111	0.7%

A unit may offer a lower economic minimum MW level on the price-based offer than the cost-based offer. Such a unit may appear to be cheaper to commit on the price-based offer even with a positive markup. A unit with a positive markup can have lower dispatch cost with the price-based offer with a lower economic minimum level compared to the cost-based offer. Figure 3-60 shows an example of offers from a unit that has a positive markup and a price-based offer with a lower economic minimum MW than the cost-based offer. Keeping the startup cost, Minimum Run Time and no load cost constant between the price-based offer and cost-based offer, the dispatch cost for this unit is lower on the price-based offer than on the cost-based offer solely as a result of the lower economic minimum MW. However, the price-based offer includes a positive markup and could result in setting the market price at a noncompetitive level even after the resource owner fails the TPS test.

Figure 3-60 Offers with a positive markup but different economic minimum MW

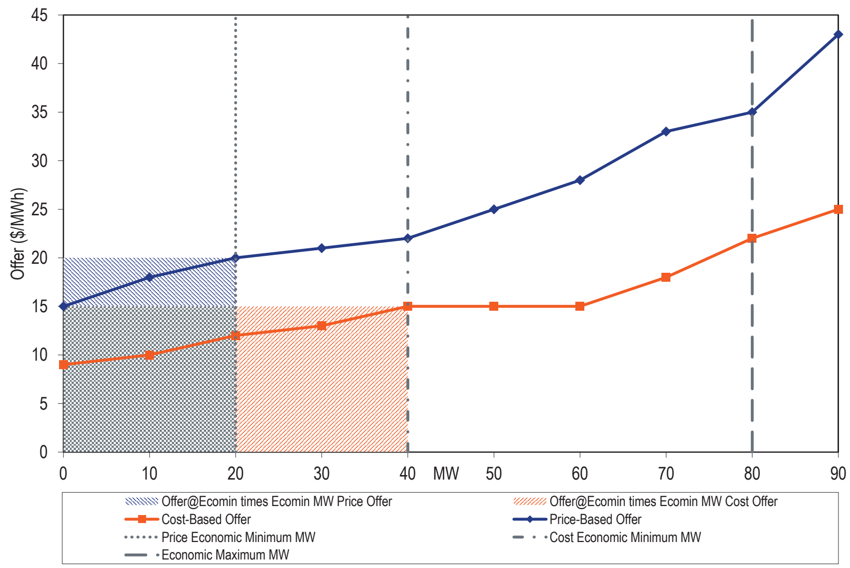


Table 3-108 shows the number and percent of unit schedule hours when units offered lower economic minimum MW in price-based offers than in cost-based offers while having a positive markup in the price-based offer.

Table 3-108 Units offered with lower economic minimum MW on price compared to cost and with positive markup: January through March, 2023

	Day-Ahead			Real-Time		
2023	Number of Schedule Hours with Lower Economic Minimum MW in Price Compared to Cost	Total Number of Cost Schedule Hours Offered by Price Based Units	Percent of Schedule Hours with Lower Economic Minimum MW in Price Compared to Cost	Number of Schedule Hours with Lower Economic Minimum MW in Price Compared to Cost	Total Number of Cost Schedule Hours Offered by Price Based Units	Percent of Schedule Hours with Lower Economic Minimum MW in Price Compared to Cost
Jan	192	838,800	0.0%	192	777,827	0.0%
Feb	144	764,688	0.0%	144	713,752	0.0%
Mar	384	847,714	0.0%	0	737,532	0.0%
Total	720	2,451,202	0.0%	336	2,229,111	0.0%

In the case of dual fuel units, if the price-based offer uses a cheaper fuel and the cost-based offer uses a more expensive fuel, the price-based offer will appear to be cheaper even when it includes a markup. Figure 3-61 shows an example of offers by a dual fuel unit, where the active cost-based offer uses a more expensive fuel and the price-based offer uses a cheaper fuel and includes a markup. Table 3-109 shows the number and percent of dual fuel unit hours where the price-based offer does not have a comparable cost-based offer with a matching fuel, and the cost-based offer exceeds the price-based offer. The analysis includes only those units that offered multiple offers (cost or price) with different fuels in the first three months of 2023.

Figure 3-61 Dual fuel unit offers

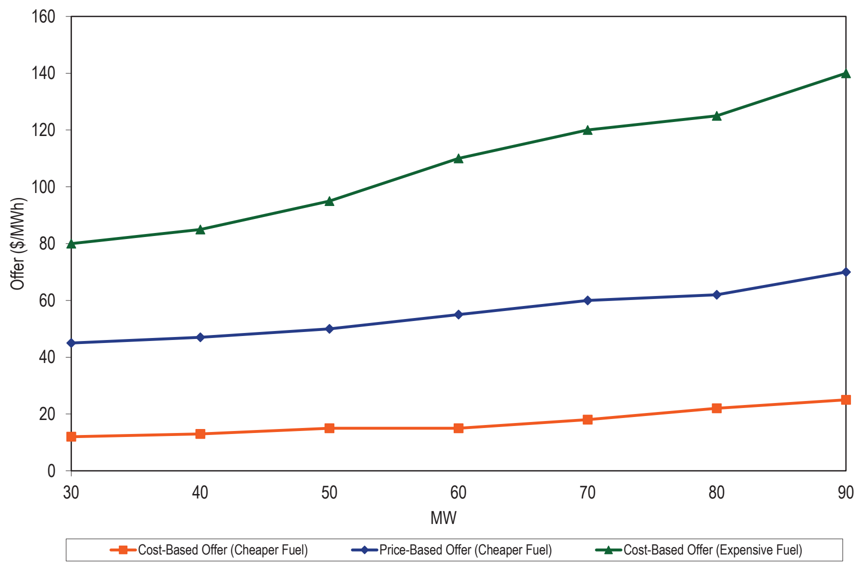


Table 3-109 Dual fuel unit offers with cost-based offers exceeding price-based offers (negative markup) but different fuel: January through March, 2023

	Day-Ahead			Real-Time		
2023	Number of Unit Hours With Negative Markup And No Matching Fuel on Cost	Total Number of Unit Hours By Units With Multiple Fuels	Percent Unit Hours With Negative Markup And No Matching Fuel on Cost	Number of Unit Hours With Negative Markup And No Matching Fuel on Cost	Total Number of Unit Hours By Units With Multiple Fuels	Percent Unit Hours With Negative Markup And No Matching Fuel on Cost
Jan	5,607	180,288	3.1%	5,607	168,984	3.3%
Feb	7,775	169,536	4.6%	7,775	158,678	4.9%
Mar	5,522	190,446	2.9%	5,522	157,797	3.5%
Total	18,904	540,270	3.5%	18,904	485,459	3.9%

These issues can be solved by simple rule changes.[172] The MMU recommends, in order to ensure effective market power mitigation when the TPS test is failed, that markup be consistently positive or negative across the full MWh range of price and cost-based offers. This means that the cost-based and price-based offer curves never cross.[173]

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

Levels of offer capping have historically been low in PJM, as shown in Table 3-111. But offer capping remains a critical element of PJM market rules because it is designed to prevent the exercise of local market power. While overall offer capping levels have been low, there are a significant number of units with persistent structural local market power that would have a significant impact on prices in the absence of local market power mitigation. Until November 1, 2017, only uncommitted resources, started to relieve a transmission constraint, were subject to offer capping. Beginning November 1, 2017, under certain circumstances, online resources that are committed beyond their original commitment (day-ahead or real-time) can be offer capped if the owner fails the TPS test, and the latest available cost-based offer is determined to be lower than the price-based offer.[174] Units running in real time as part of their original commitment on the price-based offer on economics, and that can provide incremental relief to a constraint, cannot be switched to their cost-based offer.

The offer capping percentages shown in Table 3-110 include units that are committed to provide constraint relief whose owners failed the TPS test in the energy market, but excluding units that were committed for reliability

172 The MMU proposed these offer rule changes as part of a broader reform to address generator offer flexibility and associated impact on market power mitigation rules in the Generator Offer Flexibility Senior Task Force (GOFSTF) and subsequently in the MMU's protest in the hourly offers proceeding in Docket No. ER16-372-000, filed December 14, 2015.

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

174 See OA Schedule 1 § 6.4.1.

reasons, providing black start or providing reactive support. Offer capped unit run hours and offer capped generation (in MWh) are shown as a percentage of the total run hours and the total generation (MWh) from all the units in the PJM energy market.[175] Beginning November 1, 2017, with the introduction of hourly offers, certain online units, whose owners fail the TPS test in the real-time energy market for providing constraint relief, can be offer capped and dispatched on their cost-based offer subsequent to a real-time hourly offer update.

Table 3-110 Offer capping statistics – energy only: January through March, 2018 to 2023

	Real-Time		Day-Ahead	
Year (Jan-Mar)	Unit Hours Capped	MWh Capped	Unit Hours Capped	MWh Capped
2018	1.0%	0.4%	0.1%	0.1%
2019	0.6%	0.5%	0.2%	0.2%
2020	0.7%	1.1%	0.8%	0.8%
2021	1.2%	0.9%	0.9%	0.7%
2022	1.1%	1.0%	1.4%	1.0%
2023	0.7%	0.5%	1.1%	0.5%

Table 3-111 shows the offer capping percentages including both units committed to provide constraint relief and units committed for reliability reasons, black start or reactive support. Reliability reasons include reactive support or local voltage support. PJM creates closed loop interfaces to, in some cases, model reactive constraints. The closed loop interface creates demand for the output of the resource needed to provide reactive power. The resulting higher LMPs in the closed loop interfaces increased economic dispatch, which contributed to the reduction in units offer capped for reactive support over time in Table 3-112. In instances where units are committed and offer capped for the modeled closed loop interface constraints, they are considered offer capped for providing constraint relief, and not for reliability. They are included in the offer capping percentages in Table 3-110. Prior to closed loop interfaces, these units were considered as committed for reactive support, and were included in the offer capping statistics for reliability in Table 3-112.

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

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

	Real-Time		Day-Ahead	
Year (Jan-Mar)	Unit Hours Capped	MWh Capped	Unit Hours Capped	MWh Capped
2018	1.1%	0.5%	0.1%	0.1%
2019	0.6%	0.5%	0.2%	0.2%
2020	0.7%	1.1%	0.8%	0.8%
2021	1.2%	0.9%	1.0%	0.7%
2022	1.1%	1.0%	1.4%	1.0%
2023	0.7%	0.5%	1.1%	0.6%

Table 3-112 shows the offer capping percentages only for units committed for reliability reasons, black start or reactive support. The low offer capping percentages do not mean that units manually committed for reliability reasons do not have market power. All units manually committed for reliability have market power and all are treated as if they had market power. These units are not capped to their cost-based offers because they tend to offer with a negative markup in their price-based offers, particularly at the economic minimum level, which means that PJM's offer capping process results in the use of the price-based offer for commitment. However, the price-based offers have inflexible parameters such as longer minimum run times that may lead to higher total commitment cost if the unit was only needed for a shorter period that is less than its inflexible minimum run time.

Table 3-112 Offer capping statistics for reliability: January through March, 2018 to 2023

	Real-Time		Day-Ahead	
Year (Jan-Mar)	Unit Hours Capped	MWh Capped	Unit Hours Capped	MWh Capped
2018	0.07%	0.14%	0.02%	0.04%
2019	0.00%	0.00%	0.00%	0.00%
2020	0.00%	0.00%	0.00%	0.00%
2021	0.03%	0.01%	0.03%	0.01%
2022	0.00%	0.01%	0.00%	0.00%
2023	0.03%	0.03%	0.06%	0.05%

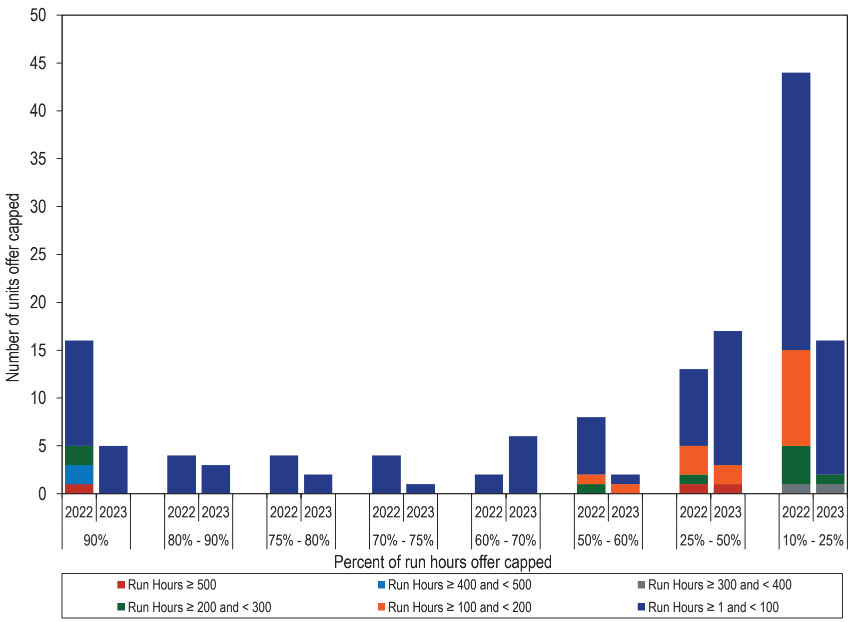
Table 3-113 presents data on the frequency with which units were offer capped in the first three months of 2022 and 2023 as a result of failing the TPS test to provide energy for constraint relief in the real-time energy market, or for reliability reasons. Table 3-113 shows that five units were offer capped for 90 percent or more of their run hours in the first three months of 2023, all of which ran for less than 100 hours, compared to 16 units with 90 percent or more offer capped run hours in the first three months of 2022, 11 of which ran for less than 100 hours.

Table 3-113 Real-time offer capped unit statistics: January through March, 2022 and 2023

		Offer-Capped Hours					
Run Hours Offer-Capped, Percent Greater Than Or Equal To:	Jan - Mar	Hours ≥ 500	Hours ≥ 400 and < 500	Hours ≥ 300 and < 400	Hours ≥ 200 and < 300	Hours ≥ 100 and < 200	Hours ≥ 1 and < 100
90%	2022	1	2	0	2	0	11
	2023	0	0	0	0	0	5
80% and < 90%	2022	0	0	0	0	0	4
	2023	0	0	0	0	0	3
75% and < 80%	2022	0	0	0	0	0	4
	2023	0	0	0	0	0	2
70% and < 75%	2022	0	0	0	0	0	4
	2023	0	0	0	0	0	1
60% and < 70%	2022	0	0	0	0	0	2
	2023	0	0	0	0	0	6
50% and < 60%	2022	0	0	0	1	1	6
	2023	0	0	0	0	1	1
25% and < 50%	2022	1	0	0	1	3	8
	2023	1	0	0	0	2	14
10% and < 25%	2022	0	0	1	4	10	29
	2023	0	0	1	1	0	14

Figure 3-62 shows the frequency with which units were offer capped in the first three months of 2022 and 2023 for failing the TPS test to provide energy for constraint relief in the real-time energy market or for reliability reasons.

Figure 3-62 Real-time offer capped unit statistics: January through March, 2022 and 2023



Markup Index

Markup is a summary measure of the degree to which a participant's offer behavior or conduct for individual units is competitive. When a seller makes a competitive offer, markup is zero. When a seller exercises market power in its offer, markup is positive. The degree of markup increases with the degree of market power. The markup index for each marginal unit is calculated as (Price – Cost)/Price.[176] The markup index is normalized and can vary from -1.00 when the offer price is less than the cost-based offer price, to 1.00 when the offer price is higher than the cost-based offer price. The markup index does not measure the impact of unit markup on total LMP. The dollar markup for a unit is the difference between price and cost.

176 In order to normalize the index results (i.e., bound the results between +1.00 and -1.00) for comparison across both low and high cost units, the index is calculated as (Price – Cost)/Price when price is greater than cost, and (Price – Cost)/Cost when price is less than cost.

Real-Time Markup Index

Table 3-114 shows the average markup index of marginal units in the real-time energy market, by offer price category using unadjusted cost-based offers. Table 3-116 shows the percentage of marginal units that had markups, calculated using unadjusted cost-based offers, below, above and equal to zero for coal, gas and oil fuel types.

Table 3-115 shows the average markup index of marginal units in the real-time energy market, by offer price category using adjusted cost-based offers. The unadjusted markup is the difference between the price-based offer and the cost-based offer including the 10 percent adder in the cost-based offer at the dispatch point on the offer curves. The adjusted markup is the difference between the price-based offer and the cost-based offer excluding the 10 percent adder from the cost-based offer. The adjusted markup is calculated for coal, gas and oil units because these units have consistently had price-based offers less than cost-based offers.[177] The markup is negative if the cost-based offer of the marginal unit is greater than its price-based offer at its operating point.

All generating units are allowed to add an additional 10 percent to their cost-based offer. The 10 percent adder was included prior to the implementation of PJM markets in 1999, based on the uncertainty of calculating the hourly operating costs of CTs under changing ambient conditions. The owners of coal units, facing competition, typically exclude the additional 10 percent from their actual offers. The owners of many gas fired and oil fired units have also begun to exclude the 10 percent adder. The introduction of hourly offers and intraday offer updates in November 2017 allows gas and oil generators to directly incorporate the impact of ambient temperature changes in fuel consumption in offers.

177 The MMU will calculate adjusted markup for gas units also in future reports because gas units also more consistently have price-based offers less than cost-based offers.

PJM implemented Fast Start Pricing on September 1, 2021. For all the fast start marginal units beginning on September 1, 2021, the markup includes markup in the incremental offer, markup in the amortized start up offer, and markup in the amortized no load offer.

Even the adjusted markup overestimates the negative markup because units facing increased competitive pressure have excluded both the 10 percent and components of operating and maintenance costs that are not short run marginal costs. The PJM Market rules permit the 10 percent adder and maintenance costs, which are not short run marginal costs, under the definition of cost-based offers. Actual market behavior reflects the fact that neither is part of a competitive offer and neither is a short run marginal cost.[178]

In the first three months of 2023, the average dollar markups of units with offer prices less than $10 was negative (-$0.02 per MWh) when using unadjusted cost-based offers. The average dollar markups of units with offer prices between $10 and $15 was negative (-$0.10 per MWh) when using unadjusted cost-based offers. Negative markup means the unit is offering to run at a price less than its cost-based offer, revealing a short run marginal cost that is less than the maximum allowable cost-based offer under the PJM Market Rules.

Some marginal units did have substantial markups. Among the units that were marginal in the first three months of 2023, 1.0 percent had offer prices above $150 per MWh. Among the units that were marginal in the first three months of 2022, 6.7 percent had offer prices greater than $150 per MWh. Using the unadjusted cost-based offers, the highest markup for any marginal unit in the first three months of 2023 was more than $200, and the highest markup in the first three months of 2022 was more than $400.

Table 3-114 Real-time average marginal unit markup index (By offer price category unadjusted): January through March, 2022 and 2023

	2022 (Jan - Mar)			2023 (Jan - Mar)		
Offer Price Category	Average Markup Index	Average Dollar Markup	Frequency	Average Markup Index	Average Dollar Markup	Frequency
< $10	5.93	($0.73)	16.9%	(0.02)	($2.42)	9.2%
$10 to $15	(0.20)	($5.12)	0.9%	(0.10)	($1.93)	6.4%
$15 to $20	(0.05)	($1.55)	1.6%	(0.04)	($1.03)	23.6%
$20 to $25	(0.00)	($0.93)	4.1%	(0.02)	($0.95)	22.8%
$25 to $50	0.02	$0.09	55.4%	(0.01)	($1.12)	33.4%
$50 to $75	0.06	$2.89	10.4%	0.21	$10.65	2.4%
$75 to $100	0.12	$10.11	2.7%	0.11	$6.98	1.0%
$100 to $125	0.11	$10.96	0.8%	0.38	$41.61	0.2%
$125 to $150	0.18	$24.35	0.4%	0.59	$76.58	0.1%
>= $150	0.02	$5.45	6.7%	0.07	$13.64	1.0%
All Offers	0.54	$0.94	100.0%	(0.02)	($0.58)	100.0%

Table 3-116 shows the percentage of marginal units that had markups, calculated using unadjusted cost-based offers, below, above and equal to zero for coal, gas and oil fuel types.[179]

Table 3-115 Real-time average marginal unit markup index (By offer price category adjusted): January through March, 2022 and 2023

	2022 (Jan - Mar)			2023 (Jan - Mar)		
Offer Price Category	Average Markup Index	Average Dollar Markup	Frequency	Average Markup Index	Average Dollar Markup	Frequency
< $10	5.93	($0.67)	16.9%	(0.02)	($2.29)	9.2%
$10 to $15	(0.14)	($3.60)	0.9%	(0.03)	($0.80)	6.4%
$15 to $20	0.03	$0.11	1.6%	0.02	$0.13	23.6%
$20 to $25	0.07	$1.07	4.1%	0.03	$0.39	22.8%
$25 to $50	0.09	$2.93	55.4%	0.05	$1.01	33.4%
$50 to $75	0.13	$7.25	10.4%	0.26	$14.06	2.4%
$75 to $100	0.19	$15.75	2.7%	0.17	$12.82	1.0%
$100 to $125	0.17	$17.96	0.8%	0.41	$45.31	0.2%
$125 to $150	0.23	$31.71	0.4%	0.61	$79.39	0.1%
>= $150	0.11	$32.36	6.7%	0.15	$35.50	1.0%
All Offers	0.61	$5.14	100.0%	0.04	$1.16	100.0%

178 See PJM. "Manual 15: Cost Development Guidelines," Rev. 39 (Jan. 18, 2022).

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

Table 3-117 shows the percentage of marginal units that had markups, calculated using adjusted cost-based offers, below, above and equal to zero for coal, gas and oil fuel types. In the first three months of 2023, using unadjusted cost-based offers for coal units, 53.94 percent of marginal coal units had negative markups. The share of marginal gas units with negative markups at the dispatch point on their offer curve increased from 41.52 percent in the first three months of 2022 to 51.83 percent in the first three months of 2023 when using unadjusted cost based offers.

Table 3-116 Percent of marginal units with markup below, above and equal to zero (By fuel type with unadjusted offers): January through March, 2022 and 2023

	2022 (Jan - Mar)			2023 (Jan - Mar)		
Type/Fuel	Negative	Zero	Positive	Negative	Zero	Positive
Coal	38.00%	12.41%	49.59%	53.94%	22.32%	23.75%
Gas	41.52%	17.99%	40.50%	51.83%	14.04%	34.13%
Oil	0.68%	99.18%	0.13%	0.96%	98.85%	0.19%

In the first three months of 2023, using adjusted cost-based offers for coal units, 43.63 percent of marginal coal units had negative markups.

Table 3-117 Percent of marginal units with markup below, above and equal to zero (By fuel type with adjusted offers): January through March, 2022 and 2023

	2022 (Jan - Mar)			2023 (Jan - Mar)		
Type/Fuel	Negative	Zero	Positive	Negative	Zero	Positive
Coal	19.10%	6.16%	74.74%	43.63%	3.71%	52.66%
Gas	27.01%	7.06%	65.93%	34.06%	6.80%	59.14%
Oil	0.66%	99.13%	0.21%	0.00%	98.85%	1.15%

Figure 3-63 shows the frequency distribution of hourly markups for all gas units offered in the first three months of 2022 and the first three months of 2023 using unadjusted cost-based offers. The highest markup within the economic operating range of the unit's offer curve was used in the frequency distributions.[180] Of the gas units offered in the PJM market in the first three months of 2023, 24.3 percent of gas unit hours had a maximum markup that was negative and 16.0 percent of gas fired unit hours had a maximum markup above $100 per MWh. The share of offered gas units with maximum markup that was negative increased in the first three months of 2023 compared to the first three months of 2022 and the share of marginal gas units with negative markups also increased.

Figure 3-63 Frequency distribution of highest markup of gas units offered using unadjusted cost offers: January through March, 2022 and 2023

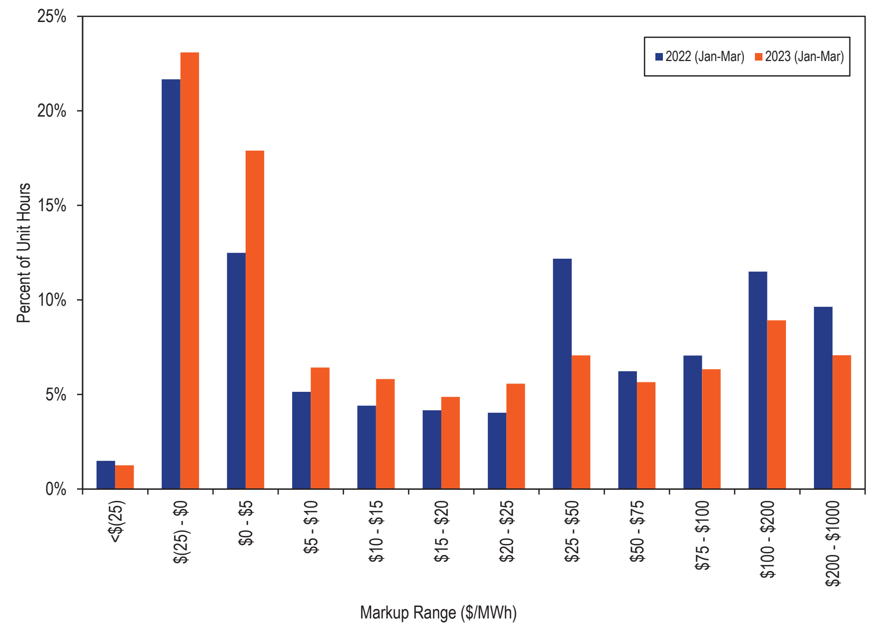


Figure 3-64 shows the frequency distribution of hourly markups for all coal units offered in the first three months of 2022 and the first three months of 2023 using unadjusted cost-based offers. Of the coal units offered in the PJM market in the first three months of 2023, 32.2 percent of coal unit hours had a maximum markup that was negative or equal to zero, increasing from 24.6 percent in the first three months of 2022. The share of offered coal units with maximum markup that was negative increased in the first three months of 2023 and the share of marginal coal units with negative markups also

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

increased in the first three months of 2023 compared to the first three months of 2022.

Figure 3-64 Frequency distribution of highest markup of coal units offered using unadjusted cost offers: January through March, 2022 and 2023

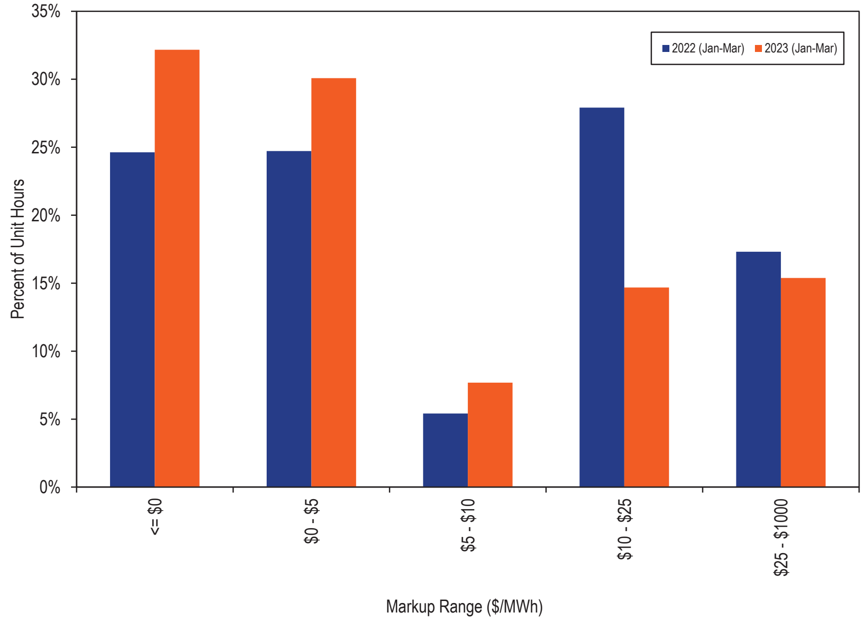
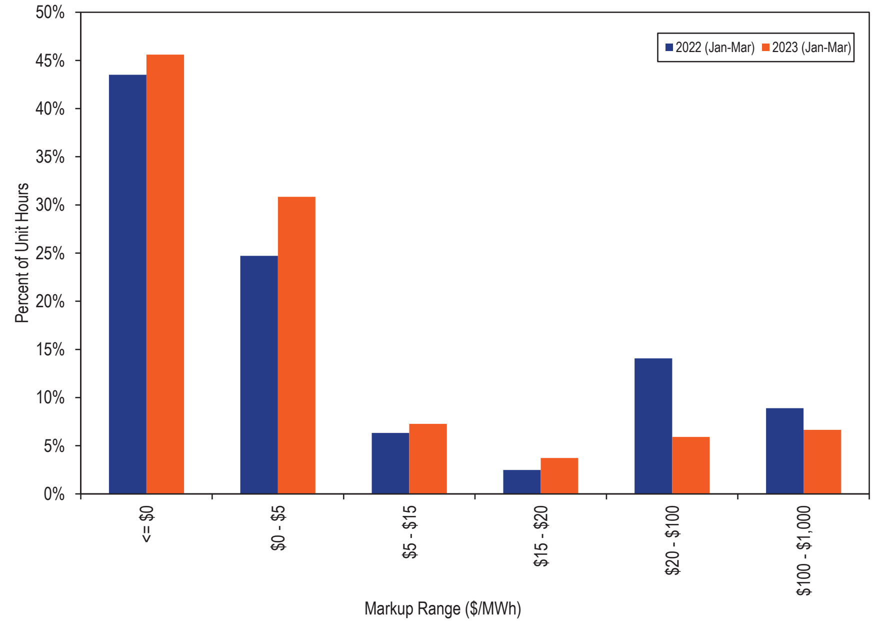


Figure 3-65 shows the frequency distribution of hourly markups for all offered oil units in the first three months of 2022 and the first three months of 2023 using unadjusted cost-based offers. Of the oil units offered in the PJM market in the first three months of 2023, 45.5 percent of oil unit hours had a maximum markup that was negative or equal to zero. More than 6.6 percent of oil fired unit hours had a maximum markup above $100 per MWh.

Figure 3-65 Frequency distribution of highest markup of oil units offered using unadjusted cost offers: January through March, 2022 and 2023

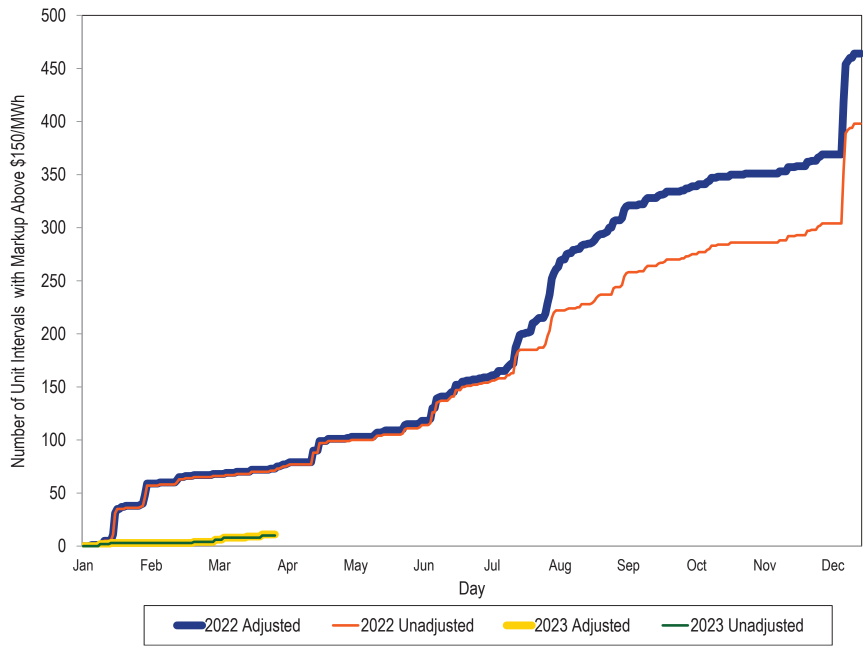


The markup frequency distributions show that a significant proportion of units make price-based offers less than the cost-based offers permitted under the PJM market rules. This behavior means that competitive price-based offers reveal actual unit marginal costs and that PJM market rules permit the inclusion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

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

Figure 3-66 shows the number of marginal unit intervals in the first three months of 2023 and the first three months of 2022 with markup above $150 per MWh.

Figure 3-66 Cumulative number of unit intervals with markups above $150 per MWh: January through March, 2022 and 2023



Day-Ahead Markup Index

Table 3-118 shows the average markup index of marginal generating units in the day-ahead energy market, by offer price category using unadjusted cost-based offers.[181] The majority of marginal units are virtual transactions, which do not have markup. The average dollar markups of units with offer prices less than $10 was negative (-$2.32 per MWh) when using unadjusted cost-based offers. In the first three months of 2023, the average dollar markups of units with offer prices between $10 and $15 was positive ($7.70 per MWh) when using unadjusted cost-based offers.

Some marginal units did have substantial markups. Using the unadjusted cost-based offers, the highest markup for any marginal unit in the day-ahead market in the first three months of 2023 was more than $150 per MWh while the highest markup in the first three months of 2022 was more than $100 per MWh.

Table 3-118 Average day-ahead marginal unit markup index (By offer price category, unadjusted): January through March, 2022 and 2023

	2022 (Jan - Mar)			2023 (Jan - Mar)		
Offer Price Category	Average Markup Index	Average Dollar Markup	Frequency	Average Markup Index	Average Dollar Markup	Frequency
< $10	15.25	$4.65	5.2%	(0.05)	($2.32)	3.2%
$10 to $15	2.29	$24.83	1.9%	0.78	$7.70	1.8%
$15 to $20	1.46	$24.11	2.6%	0.37	$5.93	6.4%
$20 to $25	0.32	$4.55	2.5%	0.16	$3.91	4.6%
$25 to $50	0.09	$2.46	59.5%	0.10	$2.23	68.2%
$50 to $75	0.13	$6.71	18.5%	0.29	$18.92	6.4%
$75 to $100	0.10	$7.59	4.3%	0.06	$3.79	2.1%
$100 to $125	0.22	$24.51	1.8%	0.16	$16.21	2.9%
$125 to $150	0.14	$18.38	0.7%	0.15	$20.38	0.7%
>= $150	0.03	$5.33	3.1%	0.19	$48.19	3.6%
All Offers	0.96	$5.20	100.0%	0.14	$5.77	100.0%

Table 3-119 shows the average markup index of marginal generating units in the day-ahead energy market, by offer price category using adjusted cost-based offers. In the first three months of 2023, 68.2 percent of day-ahead marginal generation units had offers between $25 and $50 per MWh, and the average dollar markup and the average markup index were both positive. The average markup index decreased from 15.26 in the first three months of 2022, to -0.04 in the first three months of 2023 in the offer price category less than $10.

181 The pricing run marginal resource data is used when calculating day-ahead markup index for the first three month of 2022 and 2023.

Table 3-119 Average day-ahead marginal unit markup index (By offer price category, adjusted): January through March, 2022 and 2023

	2022 (Jan - Mar)			2023 (Jan - Mar)		
Offer Price Category	Average Markup Index	Average Dollar Markup	Frequency	Average Markup Index	Average Dollar Markup	Frequency
< $10	15.26	$4.73	5.2%	(0.04)	($2.15)	3.2%
$10 to $15	2.32	$25.37	1.9%	0.85	$8.76	1.8%
$15 to $20	1.50	$24.87	2.6%	0.43	$7.25	6.4%
$20 to $25	0.38	$6.60	2.5%	0.24	$5.62	4.6%
$25 to $50	0.16	$5.72	59.5%	0.17	$5.30	68.2%
$50 to $75	0.21	$11.41	18.5%	0.35	$22.46	6.4%
$75 to $100	0.18	$14.73	4.3%	0.14	$11.39	2.1%
$100 to $125	0.29	$32.37	1.8%	0.23	$24.56	2.9%
$125 to $150	0.22	$28.91	0.7%	0.23	$30.57	0.7%
>= $150	0.12	$30.81	3.1%	0.26	$64.61	3.6%
All Offers	1.04	$9.40	100.0%	0.21	$9.35	100.0%

No Load and Start Cost Markup

Generator energy offers in PJM are comprised of three parts, an incremental energy offer curve, no load cost and start cost. In cost-based offers, all three parts are capped at the level allowed by Schedule 2 of the Operating Agreement, the Cost Development Guidelines (Manual 15) and fuel cost policies approved by PJM. In price-based offers, the incremental energy offer curve is capped at $1,000 per MWh (unless the verified cost-based offer exceeds $1,000 per MWh, but cannot exceed $2,000 per MWh). Generators are allowed to choose whether to use price-based or cost-based no load cost and start costs twice a year. If price-based is selected, the no load and start costs do not have a cap, but the offers cannot be changed for six months (April through September and October through March). If cost-based is selected, the cap is the same as the cap of the no load and start costs in the cost-based offers, and the offers can be updated daily or hourly based on changes in costs. Table 3-120 shows the caps on the three parts of cost-based and price-based offers.

Table 3-120 Cost-based and price-based offer caps

<table>
<tr><th>Offer Type</th><th>No Load and Start Cost Option</th><th>Incremental Offer Curve Cap</th><th>No Load Cost Cap</th><th>Start Cost Cap</th></tr>
<tr><td>Cost-Based</td><td>Cost-Based</td><td colspan="3">Based on OA Schedule 2, Cost Development Guidelines (Manual 15) and Fuel Cost Policies</td></tr>
<tr><td rowspan="2">Price-Based</td><td>Cost-Based</td><td rowspan="2">$1,000/MWh or based on OA Schedule 2, Cost Development Guidelines (Manual 15) and Fuel Cost Policies if verified cost-based offer exceeds $1,000/MWh but no more than $2,000/MWh.</td><td>Based on OA Schedule 2, Cost Development Guidelines (Manual 15) and Fuel Cost Policies</td><td>Based on OA Schedule 2, Cost Development Guidelines (Manual 15) and Fuel Cost Policies</td></tr>
<tr><td>Price-Based</td><td>No cap but can only be changed twice a year.</td><td>No cap but can only be changed twice a year.</td></tr>
</table>

Table 3-121 shows the number of units that chose the cost-based option and the price-based option. In the first three months of 2023, 89 percent of all generators that submitted no load or start costs chose to have cost-based no load and start costs in their price-based offers, two percentage points lower than in 2021.

Table 3-121 Number of units selecting cost-based and price-based no load and start costs: January through March, 2022 and 2023

	2022 (Jan-Mar)		2023 (Jan-Mar)	
No Load and Start Cost Option	Number of units	Percent	Number of units	Percent
Cost-Based	529	89%	508	89%
Price-Based	64	11%	64	11%
Total	593	100%	572	100%

Generators can have positive or negative markups in their no load and start costs under the price-based option. Generators cannot have positive markups in no load and start costs when they select the cost-based option. Table 3-122 shows the average markup in the no load and start costs in the first three months of 2022 and 2023. Generators that selected the cost-based start and no load option offered on average with a negative markup on the no load cost and a negative markup on the start costs. The price-based offers were lower than the cost-based offers. Generators that selected the price-based start and no load option offered on average with a negative markup on the no load cost but with very large positive markups on the start costs.

Table 3-122 No load and start cost markup: January through March, 2022 and 2023

Period	No Load and Start Cost Option	No Load Cost	Cold Start Cost	Intermediate Start Cost	Hot Start Cost
2022 (Jan-Mar)	Cost-Based	(7%)	(8%)	(9%)	(9%)
	Price-Based	(48%)	281%	309%	377%
2023 (Jan-Mar)	Cost-Based	(7%)	(8%)	(8%)	(8%)
	Price-Based	(36%)	151%	145%	164%

Energy Market Cost-Based Offers

The application of market power mitigation rules in the day-ahead energy market and the real-time energy market helps ensure competitive market outcomes even in the presence of structural market power.

Cost-based offers in PJM affect all aspects of the PJM energy market. Cost-based offers affect prices when units are committed and dispatched on their cost-based offers. In the first three months of 2023, 4.5 percent of the marginal units set prices based on cost-based offers, 5.4 percentage points lower than in the first three months of 2022.

The efficacy of market power mitigation rules depends on the definition of a competitive offer. A competitive offer is equal to short run marginal costs. The enforcement of market power mitigation rules is undermined if the definition of a competitive offer is not correct. The significance of competition metrics like markup is also undermined if the definition of a competitive offer is not correct. The definition of a competitive offer in the PJM market rules is not correct. Some unit owners include costs that are not short run marginal costs in offers, including maintenance costs. The market rules allow these overstated cost-based offers. This issue can be resolved by simple changes to the PJM market rules to incorporate a clear and accurate definition of short run marginal costs.

The efficacy of market power mitigation rules also depends on the accuracy of cost-based offers. Some unit owners use fuel cost policies that are not algorithmic, verifiable, and systematic. These inadequate fuel cost policies permit overstated fuel costs in cost-based offers.

When market power mitigation is not effective due to inaccurate cost-based offers that exceed short run marginal costs, market power causes increases in market prices above the competitive level.

Short Run Marginal Costs

Short run marginal costs are the only costs relevant to competitive offers in the energy market. Specifically, the competitive energy offer level is the short run marginal cost of production. The current PJM market rules distinguish costs includable in cost-based energy offers from costs includable in cost-based capacity market offers based on whether costs are "directly related to energy production." The rules do not provide a clear standard. Energy production is the sole purpose of a power plant. Therefore, all costs, including the sunk costs, are directly related to energy production. This current ambiguous criterion is incorrect and allows for multiple interpretations, which could lead to tariff violations. The incorrect rules lead to higher energy market prices and higher uplift.

There are three types of costs identified in PJM rules as of April 15, 2019: variable costs, avoidable costs, and fixed costs. The criterion for whether a generator may include a cost in an energy market cost-based offer, a variable cost, is that the cost is "directly related to electric production."[182]

Variable costs, as defined in the PJM rules, are comprised of short run marginal costs and avoidable costs that are directly related to electric production. Short run marginal costs are the cost of inputs consumed or converted to produce energy, and the costs associated with byproducts that result from consuming or converting materials to produce energy, net of any revenues from the sale of those byproducts. The categories of short run marginal costs are fuel costs, emission allowance costs, operating costs, and energy market opportunity costs.[183]

Avoidable costs are annual costs that would be avoided if energy were not produced over an annual period. The PJM rules divide avoidable costs into those that are directly related to electric production and those not directly related to electric production. The distinction is ambiguous at best. PJM

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

includes overhaul and maintenance costs, replacement of obsolete equipment, and overtime staffing costs in costs related to electric production. PJM includes taxes, preventative maintenance to auxiliary equipment, improvement of working equipment, maintenance expenses triggered by a time milestone (e.g. annual, weekly) and pipeline reservation charges in costs not related to electric production.

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

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

Fuel Cost Policies

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

Fuel Cost Policy Review

Table 3-123 shows the status of all fuel cost policies (FCP). As of March 31, 2023, 723 units (89 percent) had an FCP passed by the MMU and 93 units (11 percent) had an FCP failed by the MMU. The units with fuel cost policies failed by the MMU represented 20,076 MW. All units' FCPs were approved by PJM. As of March 31, 2022, 502 units did not have FCPs. Units without FCPs cannot submit nonzero cost based offers, unless they use the temporary cost method.[184]

Table 3-123 FCP Status for PJM generating units: March 31, 2023

	MMU Status			
PJM Status	Pass	Submitted	Fail	Total
Submitted	0	0	0	0
Under Review	0	0	0	0
Customer Input Required	0	0	0	0
Approved	723	0	93	816
Total	723	0	93	816

184 See OA Schedule 2 § 2.1.

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

The standards for the MMU's market power evaluation are that FCPs be algorithmic, verifiable and systematic, accurately reflecting the short run marginal cost of producing energy. In its filings with FERC, PJM agreed with the MMU that FCPs should be verifiable and systematic.[185] Verifiable means that the FCP requires a market seller to provide a fuel price that can be calculated by the MMU after the fact with the same data available to the market seller at the time the decision was made, and documentation for that data from a public or a private source. Systematic means that the FCP must document a clearly defined quantitative method or methods for calculating fuel costs, including objective triggers for each method.[186] PJM and FERC did not agree that fuel cost policies should be algorithmic, although PJM's standard effectively requires algorithmic fuel cost policies by describing the requirements.[187] Algorithmic means that the FCP must use a set of defined, logical steps, analogous to a recipe, to calculate the fuel costs. These steps may be as simple as a single number from a contract, a simple average of broker quotes, a simple average of bilateral offers, or the weighted average index price posted on the Intercontinental Exchange trading platform ('ICE').[188]

FCPs are not verifiable and systematic if they are not algorithmic. The natural gas FCPs failed by the MMU and approved by PJM are not verifiable and systematic.

Not all FCPs approved by PJM met the standard of the PJM tariff. The tariff standards that some fuel cost policies did not meet are: accuracy (reflect applicable costs accurately); and fuel contracts (reflect the market seller's applicable commodity and/or transportation contracts where it holds such contracts).[189]

The MMU failed FCPs not related to natural gas submitted by some market sellers because they do not accurately describe the short run marginal cost of

185 Answer of PJM Interconnection, L.L.C. to Protests and Comments, Docket No. ER16-372-002 (October 7, 2016) at P 11 ("October 7th Filing").
186 Protest of the Independent Market Monitor for PJM, Docket No. ER16-372-002 (September 16, 2016) at P 8 ("September 16th Filing").
187 October 7th Filing at P12; 158 FERC ¶ 61,133 at P 57 (2017).
188 September 16th Filing at P 8.
189 See PJM Operating Agreement Schedule 2 § 2.3 (a).

fuel. Some policies include contractual terms (in dollars per MWh or in dollars per MMBtu) that do not reflect the actual cost of fuel. The MMU determined that the terms used in these policies do not reflect the cost of fuel based on the information provided by the market sellers and information gathered by the MMU for similar units.

The MMU failed the remaining FCPs because they do not accurately reflect the cost of natural gas. The main issues identified by the MMU in the natural gas policies were the use of unverifiable fuel costs and the use of available market information that results in inaccurate expected costs.

Some of the failed fuel cost polices include unverifiable cost estimates. Some policies include options under which the estimate of the natural gas commodity cost can be calculated by the market seller without specifying a verifiable, systematic method. For example, some FCPs specify that the source of the natural gas cost would be communications with traders within the market seller's organization. A fuel cost from discretionary and undocumented decision making within the market seller's organization is not verifiable. The point of FCPs is to eliminate such practices as the basis for fuel costs, as most companies have done. Verifiability requires that fuel cost estimates be transparently derived from market information and that PJM or the MMU could reproduce the same fuel cost estimates after the fact by applying the methods documented in the FCP to the same inputs. Verifiable is a key requirement of an FCP. If it is not verifiable, an FCP is meaningless and has no value. Unverifiable fuel costs permit the exercise of market power.

Some of the failed fuel cost polices include the use of available market information that results in inaccurate expected costs because the information does not represent a cleared market price. Some market sellers include the use of offers to sell natural gas on ICE as the sole basis for the cost of natural gas. An offer to sell is not a market clearing price and is not an accurate indication of the expected fuel cost. The price of uncleared offers on the exchange generally exceeds the price of cleared transactions, often by a wide margin. Use of sell offers alone is equivalent to using the supply curve alone to determine the market price of a good without considering the demand curve. It is clearly incorrect.

The FCPs that failed the MMU's evaluation also fail to meet the standards defined in the PJM tariff. PJM should not have approved noncompliant fuel cost policies. The MMU recommends that PJM require that all fuel cost policies be algorithmic, verifiable, and systematic.

Cost-Based Offer Penalties

Market sellers are assessed penalties when they submit cost-based offers that do not comply with Schedule 2 of the PJM Operating Agreement and PJM Manual 15.[190] Penalties are assessed when both PJM and the MMU are in agreement.

In the first three months of 2023, 34 penalty cases were identified, 31 resulted in assessed cost-based offer penalties and three remain pending PJM's determination. These cases were for 34 units owned by 11 different companies. Table 3-124 shows the penalties by the year in which participants were notified.

Table 3-124 Cost-based offer penalty cases by year notified: May 2017 through March 2023

Year notified	Cases	Assessed penalties	Self Identified	MMU and PJM Disagreement	Pending cases	Number of units impacted	Number of companies impacted
2017	57	56	0	1	0	55	16
2018	187	161	0	26	0	138	35
2019	57	57	0	0	0	57	19
2020	142	137	24	5	0	124	25
2021	129	124	42	5	0	124	21
2022	116	116	51	0	0	110	20
2023 (Jan-Mar)	34	31	4	0	3	34	11
Total	722	682	121	37	3	456	69

Since 2017, 722 penalty cases have been identified, 682 resulted in assessed cost-based offer penalties, 37 resulted in disagreement between the MMU and PJM, three remain pending PJM's determination and 121 were self identified by market sellers. The 682 cases were from 456 units owned by 69 different companies. The total penalties were $5.1 million, charged to units that totaled 134,206 available MW. The average penalty was $1.68 per available MW. This

190 See OA Schedule 2 § 6.

means that a 100 MW unit would have paid a penalty of $4,039.[191] In some cases where the penalized unit operates, the increase to LMP and/or uplift due to the incorrect offer exceeds the amount of the penalty. Table 3-125 shows the total cost-based offer penalties since 2017 by year.

Table 3-125 Cost-based offer penalties by year: May 2017 through March 2023

Year	Number of units	Number of companies	Penalties	Average Available Capacity Charged (MW)	Average Penalty ($/MW)
2017	92	19	$556,826	16,930	$1.56
2018	127	33	$1,242,102	25,743	$2.28
2019	73	22	$378,245	15,073	$1.14
2020	140	26	$407,283	21,908	$0.85
2021	125	24	$753,463	24,808	$1.31
2022	120	20	$1,507,296	24,173	$2.60
2023 (Jan-Mar)	29	7	$213,192	5,570	$1.57
Total	706	64	$5,058,407	134,206	$1.68

The incorrect cost-based offers resulted from incorrect application of fuel cost policies, lack of approved fuel cost policies, fuel cost policy violations, miscalculation of no load costs, inclusion of prohibited maintenance costs, use of incorrect incremental heat rates, use of incorrect start cost, and use of incorrect emission costs.

2020 Fuel Cost Policy Changes

On July 28, 2020, the Commission approved tariff revisions that modified the fuel cost policy process and the cost-based offer penalties.[192]

The tariff revisions replaced the annual review process with a periodic review set by PJM. The revisions reinstated the periodic review process employed by the MMU prior to PJM's involvement in the review and approval of fuel cost policies. Monitoring participant behavior through the use of fuel cost policies is an ongoing process that necessitates frequent updates. Market sellers must revise their fuel cost policies whenever circumstances change that impact fuel pricing (e.g. different pricing points, dual fuel addition capability).

191 Cost-based offer penalties are assessed by hour. Therefore, a $1 per available MW penalty results in a total of $24 for a 1 MW unit if the violation is for the entire day.

192 172 FERC ¶ 61,094 (2020).

The tariff revisions removed the requirement for units with zero marginal cost to have an approved fuel cost policy but also included a zero offer cap for cost-based offers for units that do not have an approved fuel cost policy.

The tariff revisions allow a temporary cost offer method for units that do not have an approved fuel cost policy. The revisions allow units to submit nonzero cost-based offers without an approved fuel cost policy if they follow the temporary cost offer method. The use of the method results in cost-based offers that do not follow the fuel cost policy rules. The approach significantly weakens market power mitigation by allowing market sellers to make offers without an approved fuel cost policy. The proposed approach allows the use of an inaccurate and unsupported fuel cost calculation in place of an accurate fuel cost policy.

The MMU recommends that the temporary cost method be removed and that all units that submit nonzero cost-based offers be required to have an approved fuel cost policy.

The tariff revisions replace the fuel cost policy revocation provision with the ability for PJM to terminate fuel cost policies.

The tariff revisions reduce the penalties for noncompliant cost-based offers in two situations. When market sellers report their noncompliant cost-based offers, the penalty is reduced by 75 percent. When market sellers do not meet conditions defined to measure a potential market impact the penalty is reduced by 90 percent. The conditions include if the market seller failed the TPS test, if the unit was committed on its cost-based offer, if the unit was marginal or if the unit was paid uplift.

The tariff revisions eliminate penalties entirely when units submit noncompliant cost-based offers if PJM determines that an unforeseen event hindered the market seller's ability to submit a compliant cost-based offer. This new provision allows market sellers to not follow their fuel cost policy, submit cost-based offers that are not verifiable or systematic and not face any penalties for doing so.

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

Cost Development Guidelines

The Cost Development Guidelines contained in PJM Manual 15 do not clearly or accurately describe the short run marginal cost of generation. The MMU recommends that PJM Manual 15 be replaced or updated with a straightforward description of the components of cost-based offers based on short run marginal costs and the correct calculation of cost-based offers. In 2022, PJM made updates recommended by the MMU to Manual 15 to add straightforward descriptions for some of the most essential cost offer calculations.[193]

Variable Operating and Maintenance Costs

PJM Manual 15 and the PJM Operating Agreement Schedule 2 include rules related to VOM costs. On October 29, 2018, PJM filed tariff revisions changing the rules related to VOM costs.[194] The changes proposed by PJM attempted but failed to clarify the rules. The proposed rules defined all costs directly related to electricity production as includable in cost-based offers. This also included the long term maintenance costs of combined cycles and combustion turbines, which had been explicitly excluded in PJM Manual 15.

On April 15, 2019, FERC accepted PJM's filing order, subject to revisions requested by FERC.[195] On October 28, 2019, FERC issued a final order accepting PJM's compliance filing.[196] Regardless of the changes, the rules remain unclear and are now inconsistent with economic theory and effective market power mitigation and competitive market results.

Maintenance costs are not short run marginal costs. Generators perform maintenance during outages. Generators do not perform maintenance in the short run, while operating the generating unit. Generators do not perform maintenance in real time to increase the output of a unit. Some maintenance costs are correlated with the historic operation of a generator. Correlation between operating hours or starts and maintenance expenditures over a long run, multiyear time frame does not indicate the necessity of any specific maintenance expenditure to produce power in the short run.

A generating unit does not consume a defined amount of maintenance parts and labor in order to start. A generating unit does not consume a defined amount of maintenance parts and labor in order to produce an additional MWh. Maintenance events do not occur in the short run. The company cannot optimize its maintenance costs in the short run.

PJM allows for the calculation of VOM costs in dollars per MWh, dollars per MMBtu, dollars per run hour, dollars per equivalent operating hour (EOH) and dollars per start. The MMU converted all VOM costs into dollars per MWh using the units' heat rates, the average economic maximum and average minimum run time of the units in 2022.

The average variable operating and maintenance cost approved by PJM for combustion turbines and diesels for 2022 was five percent higher than the approved variable operating and maintenance cost approved by PJM in 2021.[197]

The average variable operating and maintenance cost approved by PJM for combined cycles for 2022 was two percent lower than the approved variable operating and maintenance cost approved by PJM in 2021.

The average variable operating and maintenance cost approved by PJM for coal units for 2022 was one percent lower than the approved variable operating and maintenance cost approved by PJM in 2021.

Table 3-126 shows the amount of capacity offered by range of VOM costs. Table 3-126 shows that 1,135 MW have an approved effective VOM above $100 per MWh and 1,736 MW have an approved effective VOM between $50 and $100 per MWh.

193 See PJM Manual 15: Cost Development Guidelines, Revision 42 (Oct. 28, 2022).
194 See PJM Interconnection Maintenance Adder Revisions to the Amended and Restated Operating Agreement, L.L.C., Docket No. EL19-8-000.
195 167 FERC ¶ 61,030 (2019).
196 168 FERC ¶ 61,134 (2019).
197 PJM reviews VOM once per year. The results reflect PJM's most recent review.

Table 3-126 Approved effective VOM costs in dollars per MWh: 2019 through 2022

	Offered MW			
Approved VOM Range ($/MWh)	2019	2020	2021	2022
$0 to $5 per MWh	69,025	71,898	64,131	65,533
$5 to $10 per MWh	37,325	30,325	34,369	38,588
$10 to $20 per MWh	14,276	15,931	21,492	17,010
$20 to $50 per MWh	5,402	4,938	5,015	7,366
$50 to $100 per MWh	2,302	3,146	2,324	1,736
Above $100 per MWh	1,159	1,044	772	1,135

The level of costs accepted by PJM for inclusion in VOM depends on PJM's interpretation of the maintenance activities or expenses directly related to electricity production and the level of detailed support provided by market sellers to PJM.

PJM's VOM review is not adequate to determine whether all costs included in VOM are compliant. PJM's VOM review focuses only on the expenses submitted for the last year of up to 20 years of data. For example, a market seller can provide data from 2010 without any supporting documentation as long as the data from 2021 (last year) has documentation. PJM's review is dependent on the level of detail provided by the market seller. Recent changes in PJM's review process, triggered by MMU questions, required more details from market sellers and have led to the appropriate exclusion of expenses that were previously included.[198]

The flaws in PJM's review process for VOM are compounded by the ambiguity in the criteria used to determine if costs are includable. PJM's definition of allowable costs for cost-based offers, "costs resulting from electric production," is so broad as to be meaningless. Most costs incurred at a generating station result from electric production in one way or another. The generator itself would not exist but for the need for electric production. PJM's broad definition cannot identify which costs associated with electric production are includable in cost-based offers. The definition is not verifiable or systematic and permits wide discretion by PJM and generators.

198 See "Maintenance Adder & Operating Cost Submission Process," 55-57 PJM presentation to the Tech Change Forum. (April 21, 2020) <https://pjm.com/-/media/committees-groups/forums/tech-change/2020/20200421-special/20200421-item-01-maintenance-adder-and-operating-cost-submission-process.ashx>.

The MMU recommends that market participants be required to document the amount and cost of consumables used when operating in order to verify that the total operating cost is consistent with the total quantity used and the unit characteristics.

The MMU recommends, given that maintenance costs are currently allowed in cost-based offers, that market participants be permitted to include only variable maintenance costs, linked to verifiable operational events and that can be supported by clear and unambiguous documentation of operational data (e.g. run hours, MWh, MMBtu) that support the maintenance cycle of the equipment being serviced/replaced.

The MMU understands that companies have different document retention policies but in order to be allowed to include maintenance costs, such costs must be verified, and they cannot be verified without documentation. Supporting documentation includes internal financial records, maintenance project documents, invoices, and contracts. Market participants should be required to provide the operational data (e.g. run hours, MWh, MMBtu) that supports the maintenance cycle of the equipment being serviced/replaced. For example, if equipment is serviced every 5,000 run hours, the market participant must include at least 5,000 run hours of historical operation in its maintenance cost history.

On February 17, 2023, PJM filed tariff revisions changing the rules related to VOM costs. The changes included separating maintenance expenses into major and minor maintenance, allowing the use of default adders for minor maintenance and operating costs and eliminating the annual review requirement for units that choose to use default adders. The proposal that included the tariff changes also included Manual 15 changes that introduced additional documentation requirements. Regarding maintenance expenses, market participants will be required to provide all supporting documentation for all expenses submitted, regardless of year. Regarding operating expenses, market participants will be required to provide the amount of consumables used during operation and the cost per unit of each consumable. On April 18, 2023, FERC accepted PJM's filing.

FERC System of Accounts

PJM Manual 15 relies on the FERC System of Accounts, which predates markets and does not define costs consistent with market economics. Market sellers should not rely solely on the FERC System of Accounts for the calculation of their variable operating and maintenance costs. The FERC System of Accounts does not differentiate between short run marginal costs and avoidable costs. The FERC System of Accounts does not differentiate between costs directly related to energy production and costs not directly related to energy production. Reliance on the FERC System of Accounts for the calculation of variable operating and maintenance costs is likely to lead to incorrect, overstated costs.

The MMU recommends removal of all references to and reliance on the FERC System of Accounts in PJM Manual 15.

Cyclic Starting and Peaking Factors

The use of cyclic starting and peaking factors for calculating VOM costs for combined cycles and combustion turbines is designed to allocate a greater proportion of long term maintenance costs to starts and the tail block of the incremental offer curve. The use of such factors is not appropriate given that long term maintenance costs are not short run marginal costs and should not be included in cost offers. PJM Manual 15 allows for a peaking cyclic factor of three, which means that a unit with a $300 per hour (EOH) VOM cost can add $180 per MWh to a 5 MW peak segment.[199]

The MMU recommends the removal of all cyclic starting and peaking factors from PJM Manual 15.

Labor Costs

PJM Manual 15 allows for the inclusion of plant staffing costs in energy market cost offers. This is inappropriate given that labor costs are not short run marginal costs.

The MMU recommends the removal of all labor costs from the PJM Manual 15. On December 2, 2022, PJM filed tariff changes removing labor costs from cost-based offers. The changes were approved by the Commission on January 10, 2023 with an effective date of June 1, 2023.[200]

Combined Cycle Start Heat Input Definition

PJM Manual 15 defines the start heat input of combined cycles as the amount of fuel used from the firing of the first combustion turbine to the close of the steam turbine breaker plus any fuel used by other combustion turbines in the combined cycle from firing to the point at which the HRSG steam pressure matches the steam turbine steam pressure. This definition is inappropriate given that after each combustion turbine is synchronized, some of the fuel is used to produce energy for which the unit is compensated in the energy market. To account for this, PJM Manual 15 requires reducing the station service MWh used during the start sequence by the output in MWh produced by each combustion turbine after synchronization and before the HRSG steam pressure matches the steam turbine steam pressure. The formula and the language in this definition are not appropriate and are unclear.

The MMU recommended changing the definition of the start heat input for combined cycles to include only the amount of fuel used from firing each combustion turbine in the combined cycle to the breaker close of each combustion turbine. This change will make the treatment of combined cycles consistent with steam turbines. Exceptions to this definition should be granted when the amount of fuel used from synchronization to steam turbine breaker close is greater than the no load heat plus the output during this period times the incremental heat rate.

In 2022, the MMU and PJM proposed changing the start cost definition of units with a steam process to include the costs from the beginning of the start sequence to dispatchable.[201] The new definition included what is commonly consider soak costs in the start cost. The new definition was combined with the elimination of make whole payments to units with a steam process for MW produced before the unit becomes dispatchable. The proposal was approved

199 The peak adder is equal to $300 times three divided by 5 MW.

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

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

by the Commission on January 10, 2023, with an effective date of June 1, 2023.[202]

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

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

Nuclear Costs

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

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

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

Pumped Hydro Costs

The calculation of pumped hydro costs for energy storage in Section 7.3 of PJM Manual 15 is inaccurate. The mathematical formulation does not take into account the purchase of power for pumping in the day-ahead market.

The MMU recommends revising the pumped hydro fuel cost calculation to include day-ahead and real-time power purchases.

Gas Pipeline Penalties

Section 2.2.2 of PJM Manual 15 states that gas pipeline penalties are not includable in cost-based offers. Penalties can be incurred by units for many situations, for example, withdrawing gas not nominated and deviating from an imposed threshold during an operational flow order. Any unit with cost-based offers that include gas pipeline penalties will be subject to penalties per Schedule 2 of the PJM Operating Agreement.

Many Market Sellers rely on independent third party quotes to estimate or determine the gas spot price. The quotes received from these third parties should not be based on incurring gas pipeline penalties. It is recommended that Market Sellers confirm with their third parties that gas is available to them without the need to incur gas pipeline penalties. If that is not possible, the units should be unavailable until the third party can confirm that gas is available without incurring penalties.

Frequently Mitigated Units (FMU) and Associated Units (AU)

The rules for determining the qualification of a unit as an FMU or AU became effective November 1, 2014. The number of units that were eligible for an FMU or AU adder declined from an average of 70 units during the first 11 months of 2014, to zero units eligible for an FMU or AU adder for the period between December 2014 and August 2019.[203] One unit qualified for an FMU adder for the months of September and October, 2019. In 2020, five units qualified for an FMU adder in at least one month. In 2021, one unit qualified for an FMU adder in January. In 2022, no units qualified for an FMU adder. In the first three months of 2023, no units qualified for an FMU adder.

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

Table 3-127 shows, by month, the number of FMUs and AUs from January 2021 through March 2023. For example, in January 2021, there were zero units that qualified as an FMU or AU in Tier 1, one unit qualified as an FMU or AU in Tier 2, and zero units qualified as an FMU or AU in Tier 3.

Table 3-127 Number of frequently mitigated units and associated units (By month): January 2021 through March 2023

	2021				2022				2023			
	Tier 1	Tier 2	Tier 3	Total Eligible for Any Adder	Tier 1	Tier 2	Tier 3	Total Eligible for Any Adder	Tier 1	Tier 2	Tier 3	Total Eligible for Any Adder
January	0	1	0	1	0	0	0	0	0	0	0	0
February	0	0	0	0	0	0	0	0	0	0	0	0
March	0	0	0	0	0	0	0	0	0	0	0	0
April	0	0	0	0	0	0	0	0				
May	0	0	0	0	0	0	0	0				
June	0	0	0	0	0	0	0	0				
July	0	0	0	0	0	0	0	0				
August	0	0	0	0	0	0	0	0				
September	0	0	0	0	0	0	0	0				
October	0	0	0	0	0	0	0	0				
November	0	0	0	0	0	0	0	0				
December	0	0	0	0	0	0	0	0				

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

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

Market Performance

Ownership of Marginal Resources

Table 3-128 shows the contribution to real-time, load-weighted LMP by individual marginal resource owners.[204] The contribution of each marginal resource to price at each load bus is calculated for each five-minute interval of the first three months of 2023, and summed by the parent company that offers the marginal resource into the real-time energy market. In the first three months of 2023, the offers of one company resulted in 14.4 percent of the real-time load-weighted PJM system LMP and the offers of the top four companies resulted in 40.9 percent of the real-time load-weighted average PJM system LMP. In the first three months of 2023, the offers of one company resulted in 15.3 percent of the peak hour real-time load-weighted PJM system LMP.

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

Table 3-128 Marginal unit contribution to real-time load-weighted LMP (By parent company): January through March, 2022 and 2023

2022 (Jan - Mar)						2023 (Jan - Mar)					
All Hours			Peak Hours			All Hours			Peak Hours		
Company	Percent of Price	Cumulative Percent	Company	Percent of Price	Cumulative Percent	Company	Percent of Price	Cumulative Percent	Company	Percent of Price	Cumulative Percent
1	12.1%	12.1%	1	11.8%	11.8%	1	14.4%	14.4%	1	15.3%	15.3%
2	11.9%	24.0%	2	11.7%	23.5%	2	10.1%	24.5%	2	9.5%	24.7%
3	10.5%	34.6%	3	11.0%	34.6%	3	8.6%	33.1%	3	8.7%	33.5%
4	7.0%	41.5%	4	7.2%	41.7%	4	7.8%	40.9%	4	8.5%	42.0%
5	5.4%	47.0%	5	5.7%	47.4%	5	7.4%	48.3%	5	7.7%	49.6%
6	5.4%	52.3%	6	4.5%	51.9%	6	7.0%	55.4%	6	6.7%	56.4%
7	4.9%	57.2%	7	4.4%	56.3%	7	4.3%	59.7%	7	3.8%	60.2%
8	4.0%	61.2%	8	3.8%	60.1%	8	2.8%	62.4%	8	3.5%	63.7%
9	3.8%	65.0%	9	3.5%	63.6%	9	2.5%	64.9%	9	2.7%	66.4%
Other (85 companies)	35.0%	100.0%	Other (81 companies)	36.4%	100.0%	Other (67 companies)	35.1%	100.0%	Other (64 companies)	33.6%	100.0%

Figure 3-67 shows the marginal unit contribution to the real-time load-weighted PJM system LMP summed by parent companies for the first three months of every year since 2012.

Figure 3-67 Marginal unit contribution to real-time load-weighted LMP (By parent company): January through March, 2013 through 2023

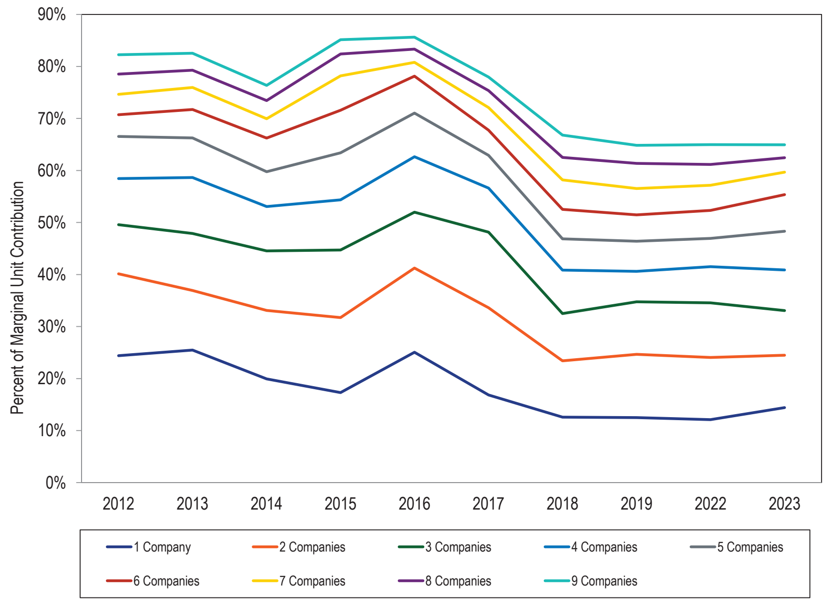


Table 3-129 shows the contribution to day-ahead, load-weighted LMP by individual marginal resource owners.[205] The contribution of each marginal resource to price at each load bus is calculated hourly, and summed by the parent company that offers the marginal resource into the day-ahead energy market. The results show that in the first three months of 2023, the offers of one company contributed 9.8 percent of the day-ahead load-weighted average PJM system LMP and that the offers of the top four companies contributed 31.6 percent of the day-ahead load-weighted average PJM system LMP.

Table 3-129 Marginal resource contribution to day-ahead load-weighted LMP (By parent company): January through March, 2022 and 2023

2022 (Jan - Mar)						2023 (Jan - Mar)					
All Hours			Peak Hours			All Hours			Peak Hours		
Company	Percent of Price	Cumulative Percent	Company	Percent of Price	Cumulative Percent	Company	Percent of Price	Cumulative Percent	Company	Percent of Price	Cumulative Percent
1	8.9%	8.9%	1	9.4%	9.4%	1	9.8%	9.8%	1	9.6%	9.6%
2	8.7%	17.7%	2	8.4%	17.9%	2	9.8%	19.7%	2	9.5%	19.0%
3	5.6%	23.3%	3	5.5%	23.4%	3	6.7%	26.4%	3	7.1%	26.2%
4	4.4%	27.7%	4	4.9%	28.3%	4	5.2%	31.6%	4	6.7%	32.9%
5	4.3%	32.0%	5	4.3%	32.6%	5	4.7%	36.3%	5	5.4%	38.3%
6	3.7%	35.7%	6	4.1%	36.7%	6	4.5%	40.8%	6	4.2%	42.5%
7	3.6%	39.3%	7	3.7%	40.4%	7	4.3%	45.2%	7	4.1%	46.6%
8	3.6%	42.9%	8	3.7%	44.1%	8	3.7%	48.9%	8	3.6%	50.2%
9	3.5%	46.5%	9	3.7%	47.7%	9	3.5%	52.4%	9	3.0%	53.2%
Other (129 companies)	53.5%	100.0%	Other (116 companies)	52.3%	100.0%	Other (116 companies)	47.6%	100.0%	Other (112 companies)	46.8%	100.0%

Markup

The markup index is a measure of the competitiveness of participant behavior for individual units. The markup in dollars is a measure of the impact of participant behavior on the generator bus market price when a unit is marginal. As an example, if unit A has a $90 cost and a $100 price, while unit B has a $9 cost and a $10 price, both would show a markup index of 10 percent, but the price impact of unit A's markup at the generator bus would be $10 while the price impact of unit B's markup at the generator bus would be $1. Depending on each unit's location on the transmission system, those bus level impacts could also have different impacts on total system price. Markup can also affect prices when units with markups are not marginal by altering the economic dispatch order of supply.

The MMU calculates an explicit measure of the impact of marginal unit incremental energy offer markups on LMP using the mathematical relationships among LMPs in the market solution.[206] The markup impact calculation sums, over all marginal units, the product of the dollar markup of the unit and the marginal impact of the unit's offer on the system load-weighted LMP. The markup impact includes the impact of the identified markup behavior of all marginal units. Positive and negative markup impacts may offset one another. The markup analysis is a direct measure of market performance. It does not take into account whether or not marginal units have either locational or aggregate structural market power.

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

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

206 The MMU calculates the impact on system prices of marginal unit price-cost markup, based on analysis using sensitivity factors. The calculation shows the markup component of LMP based on a comparison between the price-based incremental energy offer and the cost-based incremental energy offer of each actual marginal unit on the system. This is the same method used to calculate the fuel cost adjusted LMP and the components of LMP. *See* Calculation and Use of Generator Sensitivity/Unit Participation Factors, 2010 State of the Market Report for PJM: Technical Reference for PJM Markets.

marginal unit. If the actual marginal unit has short run marginal costs that would cause it to be inframarginal, a new unit would be marginal. If the offer of that new unit were greater than the cost of the original marginal unit, the markup impact would be lower than the MMU measure. If the newly marginal unit is on a price-based schedule, the analysis would have to capture the markup impact of that unit as well.

Real-Time Markup

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

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

PJM implemented fast start pricing on September 1, 2021. Under the fast start pricing rules, the LMPs are calculated in the pricing run, where the offer price of a marginal fast start unit includes amortized commitment costs. For all the fast start marginal units starting from September 1, 2021, the markup includes markup in the incremental offer, markup in the amortized start up offer and markup in the amortized no load offer.

Table 3-130 shows the impact (markup component of LMP) of the marginal unit markup behavior by fuel type and unit type on the real-time load-weighted average system LMP using unadjusted and adjusted offers. The adjusted markup component of LMP decreased from $5.29 per MWh in the first three months of 2022 to $1.95 per MWh in the first three months of 2023. The adjusted markup contribution of coal units in the first three months of 2023 was -$0.56 per MWh. The adjusted markup component of gas fired units in the first three months of 2023 was $1.88 per MWh, a decrease of $1.07 per MWh from the first three months of 2022. The markup component of wind units was $0.06 per MWh. If a price-based offer is negative, but less negative than a cost-based offer, the markup is positive. In the first three months of 2023, among the wind units that were marginal, 61.7 percent had negative offer prices.

Table 3-130 Markup component of real-time load-weighted average LMP by primary fuel type and unit type: January through March, 2022 and 2023[207]

		2022 (Jan - Mar)		2023 (Jan - Mar)	
Fuel	Technology	Markup Component of LMP (Unadjusted)	Markup Component of LMP (Adjusted)	Markup Component of LMP (Unadjusted)	Markup Component of LMP (Adjusted)
Coal	Steam	$1.48	$2.31	($0.56)	$0.00
Gas	CC	$0.62	$2.68	$0.57	$1.57
Gas	CT	($0.28)	$0.17	$0.04	$0.26
Gas	RICE	($0.01)	$0.01	($0.02)	$0.01
Gas	Steam	$0.02	$0.09	$0.00	$0.04
Municipal Waste	RICE	($0.00)	($0.00)	$0.00	$0.00
Oil	CC	($0.04)	($0.03)	($0.02)	($0.01)
Oil	CT	($0.03)	$0.05	($0.00)	$0.01
Oil	RICE	$0.00	$0.00	$0.00	$0.00
Other	Solar	$0.00	$0.00	$0.00	$0.00
Other	Steam	$0.00	$0.00	$0.00	$0.00
Wind	Wind	$0.01	$0.01	$0.06	$0.06
Total		$1.77	$5.29	$0.07	$1.95

Markup Component of Real-Time Price

Table 3-131 shows the markup component, calculated using unadjusted offers, of average prices and of average monthly on peak and off peak prices. Table 3-132 shows the markup component, calculated using adjusted offers, of average prices and of average monthly on peak and off peak prices. In the first three months of 2023, when using unadjusted cost-based offers, $0.07 per MWh of the PJM real-time load-weighted average LMP was attributable to markup. Using adjusted cost-based offers, $1.95 per MWh of the PJM real-time load-weighted average LMP was attributable to markup. In the first three months of 2023, the peak markup component was highest in March, $0.66 per MWh using unadjusted cost-based offers and peak markup component was highest in January, $2.43 per MWh using adjusted cost-based offers. This corresponds to 2.2 percent of the real-time, peak load weighted average LMP in March and 7.0 percent of the real-time, peak, load-weighted, average LMP in January.

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

Table 3-131 Monthly markup components of real-time load-weighted LMP (Unadjusted): January 2022 through March 2023

	2022			2023		
	Markup Component (All Hours)	Peak Markup Component	Off Peak Markup Component	Markup Component (All Hours)	Peak Markup Component	Off Peak Markup Component
Jan	$2.05	$0.96	$3.04	$0.45	$0.45	$0.44
Feb	$2.32	$2.19	$2.46	($0.82)	($0.39)	($1.25)
Mar	$0.88	$0.43	$1.37	$0.51	$0.66	$0.34
Apr	$4.03	$5.64	$2.42			
May	$1.93	$3.49	$0.43			
Jun	$5.83	$10.12	$0.47			
Jul	$5.65	$8.38	$3.05			
Aug	$5.62	$5.33	$5.97			
Sep	$2.09	$1.63	$2.57			
Oct	$3.89	$4.52	$3.28			
Nov	$0.95	$2.16	($0.25)			
Dec	$3.64	$5.93	$1.61			
Total	$3.32	$4.37	$2.26	$0.07	$0.26	($0.12)

Table 3-132 Monthly markup components of real-time load-weighted LMP (Adjusted): January 2022 through March 2023

	2022			2023		
	Markup Component (All Hours)	Peak Markup Component	Off Peak Markup Component	Markup Component (All Hours)	Peak Markup Component	Off Peak Markup Component
Jan	$6.10	$5.08	$7.03	$2.56	$2.70	$2.43
Feb	$5.59	$5.44	$5.74	$0.86	$1.42	$0.30
Mar	$4.03	$3.79	$4.29	$2.32	$2.56	$2.06
Apr	$8.26	$10.30	$6.23			
May	$6.60	$8.71	$4.57			
Jun	$11.35	$16.57	$4.81			
Jul	$11.65	$15.45	$8.03			
Aug	$12.48	$13.13	$11.68			
Sep	$7.61	$7.86	$7.35			
Oct	$7.60	$8.80	$6.44			
Nov	$4.36	$5.77	$2.97			
Dec	$8.69	$10.34	$7.21			
Total	$8.02	$9.54	$6.48	$1.95	$2.25	$1.64

Hourly Markup Component of Real-Time Prices

Figure 3-68 shows the markup contribution to the hourly load-weighted LMP using unadjusted cost offers in the first three months of 2022 and 2023. Figure 3-69 shows the markup contribution to the hourly load-weighted LMP using adjusted cost-based offers in the first three months of 2022 and 2023.

Figure 3-68 Markup contribution to real-time hourly load-weighted LMP (Unadjusted): 2022 and January through March, 2023

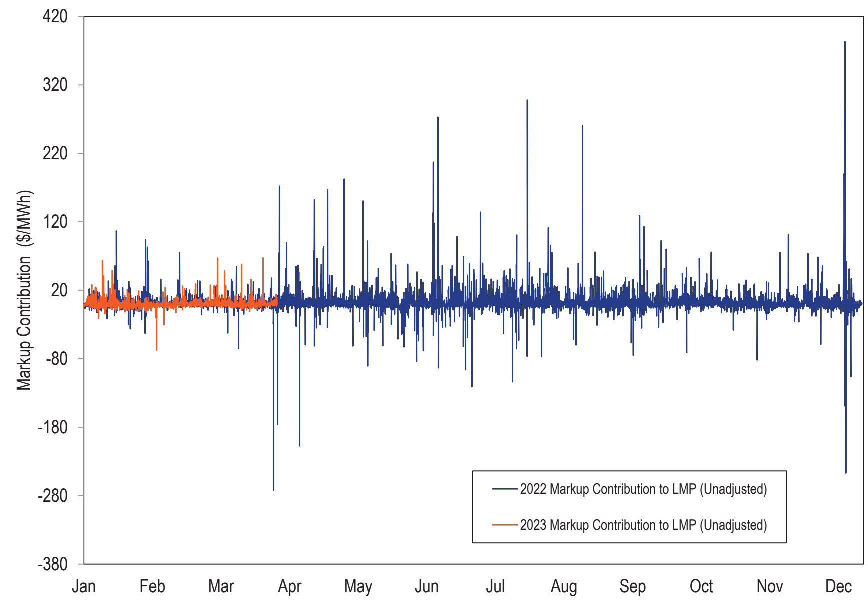
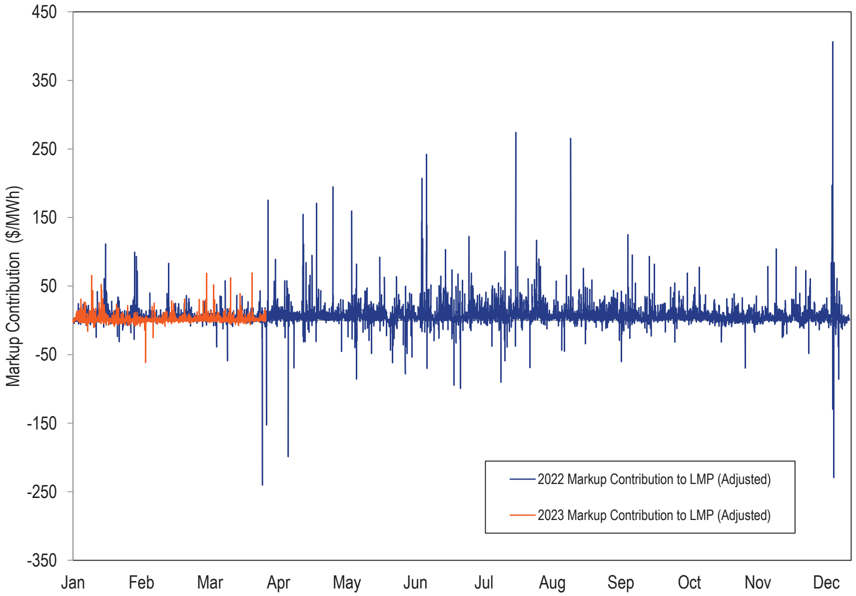


Figure 3-69 Markup contribution to real-time hourly load-weighted LMP (Adjusted): 2022 and January through March, 2023



Markup Component of Real-Time Zonal Prices

The unit markup component of average real-time price using unadjusted offers is shown for each zone in the first three months of 2022 and the first three months of 2023 in Table 3-133 and for adjusted offers in Table 3-134.[208] The smallest zonal all hours average markup component using unadjusted offers in the first three months of 2023, was in the MEC Zone, -$0.17 per MWh, while the highest was in the DAY Zone, $0.24 per MWh. The smallest zonal on peak average markup component using unadjusted offers in the first three months of 2023, was in the DPL Zone, -$0.24 per MWh, while the highest was in the BGE Zone, $0.53 per MWh.

Table 3-133 Real-time average zonal markup component (Unadjusted): January through March, 2022 and 2023

	2022 (Jan - Mar)			2023 (Jan - Mar)		
	Markup Component (All Hours)	Peak Markup Component	Off Peak Markup Component	Markup Component (All Hours)	Peak Markup Component	Off Peak Markup Component
ACEC	$1.76	$1.14	$2.36	($0.07)	($0.03)	($0.11)
AEP	$1.69	$1.41	$1.96	$0.21	$0.41	$0.01
APS	$1.53	$0.45	$2.58	$0.06	$0.32	($0.20)
ATSI	$1.78	$1.70	$1.86	$0.14	$0.33	($0.04)
BGE	$2.31	$1.15	$3.44	$0.16	$0.53	($0.21)
COMED	$0.88	$1.11	$0.66	($0.04)	$0.32	($0.40)
DAY	$1.62	$1.18	$2.06	$0.24	$0.45	$0.03
DOM	$1.92	$0.43	$3.38	$0.14	$0.33	($0.06)
DPL	$2.20	$2.18	$2.22	($0.15)	($0.24)	($0.06)
DUKE	$1.52	$1.16	$1.86	$0.22	$0.43	$0.02
DUQ	$1.67	$1.50	$1.84	$0.18	$0.37	($0.00)
EKPC	$1.66	$1.43	$1.88	$0.18	$0.42	($0.06)
JCPLC	$1.88	$1.19	$2.56	($0.10)	($0.09)	($0.10)
MEC	$2.02	$1.26	$2.75	($0.17)	$0.09	($0.43)
OVEC	$1.45	$0.97	$1.92	$0.24	$0.42	$0.06
PE	$1.72	$1.09	$2.33	$0.06	$0.26	($0.13)
PECO	$1.75	$1.26	$2.23	($0.16)	($0.22)	($0.10)
PEPCO	$1.86	$0.17	$3.50	$0.07	$0.41	($0.27)
PPL	$1.97	$1.17	$2.75	($0.04)	$0.05	($0.12)
PSEG	$2.69	$2.60	$2.78	($0.09)	($0.06)	($0.11)
REC	$3.01	$3.78	$2.26	$0.03	$0.07	($0.01)

208 A marginal unit's offer price affects LMPs in the entire PJM market. The markup component of average zonal real-time price is based on offers of units located within the zone and units located outside the transmission zone.

Table 3-134 Real-time average zonal markup component (Adjusted): January through March, 2022 and 2023

	2022 (Jan - Mar)			2023 (Jan - Mar)		
	Markup Component (All Hours)	Peak Markup Component	Off Peak Markup Component	Markup Component (All Hours)	Peak Markup Component	Off Peak Markup Component
ACEC	$5.18	$4.65	$5.69	$1.46	$1.51	$1.41
AEP	$5.09	$4.92	$5.26	$2.12	$2.44	$1.80
APS	$5.14	$4.12	$6.13	$2.01	$2.39	$1.64
ATSI	$5.14	$5.19	$5.11	$2.05	$2.35	$1.74
BGE	$6.33	$5.14	$7.50	$2.30	$2.83	$1.77
COMED	$3.94	$4.38	$3.51	$1.74	$2.26	$1.23
DAY	$5.12	$4.81	$5.42	$2.22	$2.57	$1.88
DOM	$5.88	$4.40	$7.32	$2.28	$2.65	$1.91
DPL	$5.92	$5.98	$5.85	$1.40	$1.32	$1.47
DUKE	$4.90	$4.67	$5.13	$2.15	$2.48	$1.83
DUQ	$4.92	$4.83	$5.01	$2.06	$2.36	$1.76
EKPC	$5.05	$4.93	$5.17	$2.10	$2.47	$1.73
JCPLC	$5.43	$4.87	$5.98	$1.51	$1.54	$1.47
MEC	$5.63	$4.91	$6.33	$1.63	$1.95	$1.32
OVEC	$4.79	$4.42	$5.15	$2.13	$2.43	$1.83
PE	$5.22	$4.74	$5.69	$1.91	$2.21	$1.62
PECO	$5.14	$4.70	$5.57	$1.32	$1.27	$1.37
PEPCO	$5.91	$4.19	$7.58	$2.15	$2.62	$1.68
PPL	$5.38	$4.58	$6.15	$1.59	$1.73	$1.45
PSEG	$6.36	$6.48	$6.24	$1.53	$1.59	$1.47
REC	$6.88	$8.01	$5.77	$1.75	$1.88	$1.61

Markup by Real-Time Price Levels

Table 3-135 shows the markup contribution to the LMP, based on the unadjusted cost-based offers and adjusted cost-based offers of the marginal units, when the PJM system wide load-weighted average LMP was in the identified price range.

Table 3-135 Real-time markup contribution (By load-weighted LMP category, unadjusted): January through March, 2022 and 2023

	2022 (Jan - Mar)		2023 (Jan - Mar)	
LMP Category	Markup Component	Frequency	Markup Component	Frequency
$10 to $15	$0.00	0.0%	($1.50)	1.2%
$15 to $20	($1.37)	0.6%	($0.96)	16.6%
$20 to $25	($1.39)	1.5%	($1.00)	25.9%
$25 to $50	$0.31	65.1%	($0.43)	50.5%
$50 to $75	$2.86	22.6%	$6.53	4.7%
$75 to $100	$3.15	5.2%	$31.83	0.7%
$100 to $125	$5.53	1.8%	$22.79	0.2%
$125 to $150	$18.44	1.0%	$20.57	0.1%
>= $150	$15.55	2.1%	$27.81	0.1%

Table 3-136 Real-time markup contribution (By load-weighted LMP category, adjusted): January through March, 2022 and 2023

	2022 (Jan - Mar)		2023 (Jan - Mar)	
LMP Category	Markup Component	Frequency	Markup Component	Frequency
$10 to $15	$0.00	0.0%	($0.27)	1.2%
$15 to $20	$0.22	0.6%	$0.29	16.6%
$20 to $25	$0.53	1.5%	$0.49	25.9%
$25 to $50	$3.35	65.1%	$1.70	50.5%
$50 to $75	$6.85	22.6%	$9.36	4.7%
$75 to $100	$8.20	5.2%	$34.55	0.7%
$100 to $125	$11.40	1.8%	$25.81	0.2%
$125 to $150	$25.10	1.0%	$24.46	0.1%
>= $150	$20.66	2.1%	$32.21	0.1%

Markup by Company

Table 3-137 shows the markup contribution based on the unadjusted cost-based offers and adjusted cost-based offers to real-time load-weighted average LMP by individual marginal resource owners. The markup contribution of each marginal resource to price at each load bus is calculated for each five-minute interval, and summed by the parent company that offers the marginal resource into the real-time energy market. In the first three months of 2023, when using unadjusted cost-based offers, the markup of one company accounted for 2.3 percent of the load-weighted average LMP, the markup of the top five companies accounted for 5.3 percent of the load-weighted average LMP and the markup of all companies accounted for 0.2 percent of the load-weighted average LMP. The share of top five companies' markup contribution to the load-weighted average LMP increased and the dollar values of their markup decreased in the first three months of 2023. The markup contribution to the load-weighted average LMP decreased and share of the markup contribution to the load-weighted average LMP decreased in the first three months of 2023. The markup contribution of a unit to the real-time load-weighted average LMP can be positive or negative.

Table 3-137 Markup component of real-time load-weighted average LMP by Company: January through March, 2022 and 2023

	2022 (Jan - Mar)				2023 (Jan - Mar)			
	Markup Component of LMP (Unadjusted)		Markup Component of LMP (Adjusted)		Markup Component of LMP (Unadjusted)		Markup Component of LMP (Adjusted)	
	$/MWh	Percent of Load Weighted LMP	$/MWh	Percent of Load Weighted LMP	$/MWh	Percent of Load Weighted LMP	$/MWh	Percent of Load Weighted LMP
Top 1 Company	$0.76	1.4%	$1.03	1.9%	$0.70	2.3%	$0.87	2.9%
Top 2 Companies	$1.35	2.5%	$1.92	3.6%	$1.04	3.4%	$1.28	4.2%
Top 3 Companies	$1.76	3.3%	$2.48	4.6%	$1.30	4.3%	$1.58	5.2%
Top 4 Companies	$2.09	3.9%	$2.93	5.4%	$1.46	4.8%	$1.86	6.2%
Top 5 Companies	$2.40	4.4%	$3.32	6.1%	$1.59	5.3%	$2.07	6.8%
All Companies	$1.77	3.3%	$5.29	9.8%	$0.07	0.2%	$1.94	6.4%

Day-Ahead Markup[209]

Markup Component of Day-Ahead Price by Fuel, Unit Type

The markup component of the PJM day-ahead load-weighted average LMP by primary fuel and unit type is shown in Table 3-138. INC, DEC and up to congestion transactions (UTC) have zero markups. UTCs were 57.3 percent of marginal resources, INCs were 13.3 percent of marginal resources and DECs were 16.9 percent of marginal resources in the first three months of 2023.

The adjusted markup of coal, gas and oil units is calculated as the difference between the price-based offer and the cost-based offer excluding the 10 percent adder. Table 3-138 shows the markup component of LMP for marginal generating resources. Generating resources were only 12.1 percent of marginal resources in the first three months of 2023. Using adjusted cost-based offers, the markup component of LMP for marginal generating resources decreased for coal fired steam units from $2.91 to -$0.13 per MWh and decreased for gas fired CC units from $1.62 to $0.96 per MWh.

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

Table 3-138 Markup component of day-ahead load-weighted average LMP by primary fuel type and technology type: January through March, 2022 and 2023

		2022 (Jan - Mar)			2023 (Jan - Mar)		
Fuel	Technology	Markup Component of LMP (Unadjusted)	Markup Component of LMP (Adjusted)	Frequency	Markup Component of LMP (Unadjusted)	Markup Component of LMP (Adjusted)	Frequency
Coal	Steam	$2.03	$2.91	35.7%	($0.81)	($0.13)	28.2%
Gas	CC	$0.53	$1.62	47.7%	$0.50	$0.96	53.3%
Gas	CT	$0.03	$0.04	1.3%	$0.06	$0.08	1.5%
Gas	RICE	($0.00)	$0.00	0.4%	$0.00	$0.00	0.4%
Gas	Steam	($0.00)	$0.03	2.3%	($0.01)	$0.02	2.5%
Municipal Waste	RICE	($0.00)	($0.00)	0.0%	$0.00	$0.00	0.0%
Oil	CC	$0.01	$0.01	0.2%	($0.00)	$0.00	0.0%
Oil	CT	($0.00)	$0.00	2.4%	($0.00)	($0.00)	0.0%
Oil	Steam	$0.00	$0.00	0.0%	($0.00)	$0.00	0.1%
Other	Solar	$0.01	$0.01	0.1%	$0.08	$0.08	0.6%
Other	Steam	$0.00	$0.00	0.2%	$0.00	$0.00	0.0%
Uranium	Steam	$0.00	$0.00	0.1%	$0.00	$0.00	0.0%
Water	Hydro	$0.00	$0.00	0.0%	$0.00	$0.00	0.1%
Wind	Wind	$0.47	$0.47	9.6%	$0.62	$0.62	13.2%
Total		$3.07	$5.10	100.0%	$0.44	$1.62	100.0%

Markup Component of Day-Ahead Price

The markup component of price is the difference between the system price, when the system price is determined by the active offers of the marginal units, whether price or cost-based, and the system price, based on the cost-based offers of those marginal units. Only hours when generating units were marginal on either priced-based offers or on cost-based offers were included in the markup calculation.

Table 3-139 shows the markup component of average prices and of average monthly on peak and off peak prices using unadjusted cost-based offers. In the first three months of 2023, when using unadjusted cost-based offers, $0.44 per MWh of the PJM day-ahead load-weighted average LMP was attributable to markup. In the first three months of 2023, the peak markup component was highest in January, $1.43 per MWh using unadjusted cost-based offers and the off peak markup component was highest in January, $0.77 per MWh.

Table 3-139 Monthly markup components of day-ahead (Unadjusted) load-weighted LMP: January through March, 2022 and 2023

	2022 (Jan - Mar)			2023 (Jan - Mar)		
	Markup Component (All Hours)	Peak Markup Component	Off Peak Markup Component	Markup Component (All Hours)	Peak Markup Component	Off Peak Markup Component
Jan	$3.96	$4.26	$3.68	$1.09	$1.43	$0.77
Feb	$3.36	$3.54	$3.19	($0.16)	$0.31	($0.64)
Mar	$1.71	$1.35	$2.10	$0.33	$0.91	($0.31)
Apr	$3.79	$5.20	$2.38			
May	$4.07	$5.42	$2.75			
Jun	$5.33	$7.99	$1.97			
Jul	$6.86	$9.93	$3.92			
Aug	$5.02	$7.61	$1.78			
Sep	$3.37	$4.42	$2.27			
Oct	$1.83	$2.16	$1.51			
Nov	($0.20)	$0.21	($0.60)			
Dec	$5.28	$4.08	$6.35			
Total	$3.83	$4.90	$2.73	$0.44	$0.90	($0.02)

Table 3-140 shows the markup component of average prices and of average monthly on peak and off peak prices using adjusted cost-based offers. In the first three months of 2023, when using adjusted cost-based offers, $1.62 per MWh of the PJM day-ahead, load-weighted average LMP was attributable to markup. In the first three months of 2023, the peak markup component was highest in January, $2.51 per MWh using adjusted cost-based offers and the off peak markup component was highest in January, $1.98 per MWh.

Table 3-140 Monthly markup components of day-ahead (Adjusted) load-weighted LMP: January 2022 through March 2023

	2022 (Jan - Mar)			2023 (Jan - Mar)		
	Markup Component (All Hours)	Peak Markup Component	Off Peak Markup Component	Markup Component (All Hours)	Peak Markup Component	Off Peak Markup Component
Jan	$6.45	$6.95	$6.00	$2.23	$2.51	$1.98
Feb	$5.25	$5.39	$5.10	$1.11	$1.53	$0.70
Mar	$3.32	$2.90	$3.78	$1.47	$2.05	$0.82
Apr	$5.59	$6.71	$4.48			
May	$6.04	$7.09	$5.02			
Jun	$7.23	$9.48	$4.38			
Jul	$9.22	$12.06	$6.49			
Aug	$7.60	$9.85	$4.79			
Sep	$5.79	$6.60	$4.93			
Oct	$3.05	$3.20	$2.90			
Nov	$1.14	$1.65	$0.64			
Dec	$8.29	$6.35	$10.02			
Total	$5.92	$6.77	$5.04	$1.62	$2.04	$1.20

Markup Component of Day-Ahead Zonal Prices

The markup component of annual average day-ahead price using unadjusted cost-based offers is shown for each zone in Table 3-141. The markup component of annual average day-ahead price using adjusted cost-based offers is shown for each zone in Table 3-142. The smallest zonal all hours average markup component using unadjusted cost-based offers for the first three months of 2023 was in the PE Zone, -$2.60 per MWh, while the highest was in the APS Zone, $2.02 per MWh. The smallest zonal on peak average markup using unadjusted cost-based offers was in the PE Zone, -$4.97 per MWh, while the highest was in the APS Zone, $4.11 per MWh.

Table 3-141 Day-ahead average zonal markup component (Unadjusted): January through March, 2022 and 2023

	2022 (Jan - Mar)			2023 (Jan - Mar)		
	Markup Component (All Hours)	Peak Markup Component	Off Peak Markup Component	Markup Component (All Hours)	Peak Markup Component	Off Peak Markup Component
ACEC	$3.11	$3.05	$3.16	$0.74	$1.60	($0.09)
AEP	$3.21	$3.29	$3.14	$0.81	$1.61	$0.03
APS	$3.32	$3.24	$3.40	$2.02	$4.11	($0.06)
ATSI	$3.36	$3.36	$3.35	$0.57	$1.00	$0.13
BGE	$3.23	$3.56	$2.92	$0.35	$0.96	($0.24)
COMED	$3.07	$3.00	$3.14	$1.08	$2.07	$0.05
DAY	$3.45	$3.41	$3.50	$0.51	$0.89	$0.12
DOM	$2.66	$2.41	$2.89	($1.23)	($2.36)	($0.16)
DPL	$3.33	$4.04	$2.68	$0.68	$1.36	$0.02
DUKE	$3.49	$3.52	$3.46	$0.81	$1.50	$0.10
DUQ	$3.27	$3.37	$3.17	$0.81	$1.53	$0.10
EKPC	$3.43	$3.62	$3.27	$1.15	$2.30	$0.10
JCPLC	$3.04	$3.04	$3.03	$0.47	$0.97	($0.05)
MEC	$2.73	$3.03	$2.43	$0.33	$0.69	($0.05)
OVEC	$2.09	$1.42	$2.51	($0.03)	$0.63	($0.86)
PE	$3.04	$3.32	$2.74	($2.60)	($4.97)	$0.03
PECO	$2.75	$2.52	$2.97	$0.97	$1.87	$0.05
PEPCO	$2.92	$3.02	$2.82	$0.13	$0.47	($0.21)
PPL	$3.25	$3.28	$3.21	$0.63	$1.21	$0.03
PSEG	$2.74	$2.71	$2.77	$0.63	$1.48	($0.25)
REC	$2.98	$3.20	$2.76	$0.54	$1.42	($0.47)

Table 3-142 Day-ahead average zonal markup component (Adjusted): January through March, 2022 and 2023

	2022 (Jan - Mar)			2023 (Jan - Mar)		
	Markup Component (All Hours)	Peak Markup Component	Off Peak Markup Component	Markup Component (All Hours)	Peak Markup Component	Off Peak Markup Component
ACEC	$5.22	$5.09	$5.35	$1.66	$2.36	$0.99
AEP	$5.18	$5.30	$5.06	$2.01	$2.75	$1.28
APS	$5.40	$5.32	$5.47	$3.03	$4.85	$1.23
ATSI	$5.34	$5.38	$5.28	$1.79	$2.19	$1.37
BGE	$5.59	$5.91	$5.30	$1.75	$2.31	$1.20
COMED	$4.79	$4.82	$4.76	$2.17	$3.14	$1.17
DAY	$5.46	$5.47	$5.45	$1.78	$2.13	$1.42
DOM	$4.92	$4.68	$5.14	$0.29	($0.70)	$1.21
DPL	$5.17	$5.93	$4.46	$1.55	$2.09	$1.03
DUKE	$5.45	$5.54	$5.35	$2.02	$2.67	$1.37
DUQ	$5.23	$5.37	$5.08	$1.99	$2.65	$1.32
EKPC	$5.41	$5.65	$5.20	$2.33	$3.39	$1.37
JCPLC	$5.14	$5.25	$5.02	$1.49	$1.91	$1.06
MEC	$4.90	$5.21	$4.58	$1.42	$1.71	$1.12
OVEC	$3.95	$3.35	$4.33	$1.14	$1.98	$0.08
PE	$4.91	$5.28	$4.52	($1.07)	($3.14)	$1.23
PECO	$4.83	$4.59	$5.07	$1.82	$2.55	$1.07
PEPCO	$5.26	$5.35	$5.17	$1.50	$1.80	$1.20
PPL	$5.27	$5.28	$5.26	$1.64	$2.12	$1.14
PSEG	$4.79	$4.69	$4.88	$1.60	$2.32	$0.86
REC	$4.92	$5.11	$4.72	$1.58	$2.33	$0.70

Table 3-142 shows that the smallest zonal all hours average markup component using adjusted cost-based offers for the first three months of 2023 was in the PE Zone, -$1.07 per MWh, while the highest was in the APS Zone, $3.03 per MWh. The smallest zonal on peak average markup using adjusted cost-based offers was in the PE Zone, -$3.14 per MWh, while the highest was in the APS Zone, $4.85 per MWh.

Markup by Day-Ahead Price Levels

Table 3-143 and Table 3-144 show the average markup component of LMP, based on the unadjusted cost-based offers and adjusted cost-based offers of the marginal units, when the PJM system LMP was in the identified price range.

Table 3-143 Day-ahead average markup component (By LMP category, unadjusted): January through March, 2022 and 2023

	2022 (Jan - Mar)		2023 (Jan - Mar)	
LMP Category	Average Markup Component	Frequency	Average Markup Component	Frequency
$15 to $20	($0.00)	0.4%	($0.01)	8.8%
$20 to $25	$0.00	0.6%	($0.08)	22.2%
$25 to $50	$1.00	57.0%	$0.24	65.5%
$50 to $75	$1.23	31.0%	$0.23	1.9%
$75 to $100	$0.58	7.7%	($0.03)	1.1%
$100 to $125	$0.23	2.8%	($0.02)	0.2%
$125 to $150	($0.00)	0.5%	($0.00)	0.2%
>= $150	$0.03	0.1%	$0.12	0.2%

Table 3-144 Day-ahead average markup component (By LMP category, adjusted): January through March, 2022 and 2023

	2022 (Jan - Mar)		2023 (Jan - Mar)	
LMP Category	Average Markup Component	Frequency	Average Markup Component	Frequency
$15 to $20	$0.00	0.4%	$0.04	8.8%
$20 to $25	$0.01	0.6%	$0.14	22.2%
$25 to $50	$2.05	57.0%	$1.09	65.5%
$50 to $75	$1.92	31.0%	$0.23	1.9%
$75 to $100	$0.78	7.7%	$0.01	1.1%
$100 to $125	$0.30	2.8%	($0.01)	0.2%
$125 to $150	($0.00)	0.5%	$0.00	0.2%
>= $150	$0.03	0.1%	$0.12	0.2%

Market Structure, Participant Behavior, and Market Performance

The goal of regulation through competition is to achieve competitive market outcomes even in the presence of market power. Market structure in the PJM energy market is not competitive in local markets created by transmission constraints. At times, market structure is not competitive in the aggregate energy market. Market sellers pursuing their financial interests may choose behavior that benefits from structural market power in the absence of an effective market power mitigation program. The overall competitive assessment evaluates the extent to which participant behavior results in competitive or above competitive pricing. The competitive assessment brings together the structural measures of market power, HHI and pivotal suppliers, with participant behavior, specifically markup, and pricing outcomes.

HHI and Markup

In theory, the HHI provides insight into the relationship between market structure, behavior, and performance. In the case where participants compete by producing output at constant, but potentially different, marginal costs, the HHI is directly proportional to the expected average price cost markup in the market:[210]

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

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

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

higher prices on customers. The Lerner Index is a measure of market power that connects market structure (HHI and demand elasticity) to market performance (markup).

The PJM energy market HHIs and application of the FERC concentration categories understate the degree of market power because, in the absence of aggregate market power mitigation, even the unconcentrated HHI level implies substantial markups due to the low short run price elasticity of demand. For example, research estimates find short run electricity demand elasticity ranging from -0.2 to -0.4.[211] Using the Lerner Index, the elasticity of -0.2 implies, for example, an average markup ranging from 25 to 50 percent at the low end of the moderately concentrated threshold HHI of 1000:[212]

$$\frac{HHI}{\varepsilon} = \frac{0.1}{0.2} = \frac{P - MC}{P} = 50\ percent$$

With knowledge of HHI, elasticity, and marginal cost, one can solve for the price level theoretically indicated by the Lerner Index, based on profit maximizing behavior including the exercise of market power. With marginal costs of $30.21 per MWh and an average HHI of 677 in the first nine months of 2023, average PJM prices would theoretically range from $36 to $46 per MWh, an implied markup of 16.9 to 33.9 percent, using the elasticity range of -0.2 to -0.4.[213] Given the elasticity estimates, the theoretical prices exceed marginal costs because the exercise of market power is profit maximizing in the absence of market power mitigation. Actual prices, averaging $30.28 per MWh with markups at -3.1 percent, are lower than the theoretical range, supporting the MMU's competitive assessment of the market. However, markup is not zero. In some market intervals, markup and prices reach levels that reflect the exercise of market power.

211 See Patrick, Robert H. and Frank A. Wolak (1997), "Estimating the Customer-Level Demand for Electricity Under Real-Time Market Prices," <https://web.stanford.edu/group/fwolak/cgi-bin/sites/default/files/files/Estimating%20the%20Customer-Level%20Demand%20for%20Electricity%20Under%20Real-Time%20Market%20Prices_Aug%201997_Patrick,%20Wolak.pdf>, last accessed August 3, 2018 and Fan, Shu and Rob Hyndman (2010), "The price elasticity of electricity demand in South Australia," <https://robjhyndman.com/papers/Elasticity2010.pdf>.

212 The HHI used in the equation is based on market shares. For the FERC HHI thresholds and standard HHI reporting, market shares are multiplied by 100 prior to squaring the market shares.

213 The average HHI is found in Table 3-D1. Marginal costs are the sum of all components of LMP except markup, as shown in Table 3-B-60.

Market Power Mitigation and Markup

Fully effective market power mitigation would not allow a seller that fails the structural market power test (the TPS test) to set prices with a positive markup. With the flaws in PJM's implementation of the TPS test, resources can and do set prices with a positive markup while failing the TPS test.

Table 3-145 categorizes day-ahead and real-time marginal unit intervals by markup level and TPS test status. In the first three months of 2023, 3.6 percent of real-time marginal unit intervals and 3.2 percent of day-ahead marginal unit hours included a positive markup even though the resource failed the TPS test for local market power. Unmitigated local market power affects PJM market prices. Zero markup with a TPS test failure indicates the mitigation of a marginal unit.

Table 3-145 Percent of real-time marginal unit intervals with markup and local market power: January through March, 2023

	Day-ahead Market			Real-time Market		
Markup Category	Not Failing TPS Test	Failing TPS Test	Percent in Category	Not Failing TPS Test	Failing TPS Test	Percent in Category
Negative Markup	32.8%	4.2%	37.0%	43.0%	6.1%	49.0%
Zero Markup	21.9%	5.8%	27.7%	13.5%	5.6%	19.1%
$0 to $5	10.6%	1.6%	12.2%	18.2%	3.1%	21.3%
$5 to $10	10.6%	1.3%	11.9%	5.7%	0.2%	5.9%
$10 to $15	3.9%	0.3%	4.2%	1.5%	0.1%	1.6%
$15 to $20	2.9%	0.0%	2.9%	1.1%	0.0%	1.1%
$20 to $25	1.0%	0.0%	1.0%	0.7%	0.0%	0.7%
$25 to $50	1.6%	0.0%	1.6%	0.8%	0.0%	0.9%
$50 to $75	0.6%	0.0%	0.6%	0.2%	0.0%	0.2%
$75 to $100	1.0%	0.0%	1.0%	0.1%	0.0%	0.1%
Above $100	0.0%	0.0%	0.0%	0.1%	0.0%	0.1%
Total Positive Markup	32.2%	3.2%	35.4%	28.3%	3.6%	31.9%
Total	86.8%	13.2%	100.0%	84.8%	15.2%	100.0%

The markup of marginal units was zero or negative in 68.1 percent of real-time marginal unit intervals and 64.6 percent of day-ahead marginal unit intervals in the first three months of 2023. Zero and negative markup are the expected results in a competitive market. Pivotal suppliers in the aggregate market also set prices with high markups in the first nine months of 2023.

The 32.2 percent of day-ahead marginal units and 28.3 percent of real-time marginal units setting price with a markup without failing the TPS test could represent units with aggregate market power or units that maintain markup in their offer for times when they have local market power. Allowing positive markups to affect prices in the presence of market power permits the exercise of market power and has a negative impact on the competitiveness of the PJM energy market. This problem can and should be addressed.

Energy Uplift (Operating Reserves)

In a well designed wholesale power market, energy uplift is paid as credits to market participants under specified conditions in order to ensure that competitive energy and ancillary service market outcomes do not require efficient resources operating at the direction of PJM, to operate at a loss.[1] Referred to in PJM as operating reserve credits, lost opportunity cost credits, dispatch differential lost opportunity credits, reactive services credits, synchronous condensing credits or black start services credits, these uplift payments are intended to be one of the incentives to generation owners to offer their energy to the PJM energy market for dispatch based on short run marginal costs and to operate their units as directed by PJM. These uplift credits are paid by PJM market participants as operating reserve charges, reactive services charges, synchronous condensing charges or black start services charges. Fast start pricing, implemented on September 1, 2021, required a new uplift credit to pay the lost opportunity costs of units that are backed down in real time to accommodate the less flexible fast start units for which fast start pricing assumes flexibility. The result is to create a greater reliance on uplift rather than price signals as an incentive to follow PJM's instructions.

Uplift is an inherent part of the PJM market design. Part of uplift is the result of the nonconvexity of power production costs. Uplift payments cannot be eliminated, but uplift payments should be limited to the efficient level. In wholesale power market design, a choice must be made between efficient prices and prices that fully compensate costs. Economists recognize that no single price achieves both goals in markets with nonconvex production costs, like the costs of producing electric power.[2] [3] In wholesale power markets like PJM, efficient prices equal the short run marginal cost of production by location. The dispatch of generators based on these efficient price signals minimizes the total market cost of production. For generators with nonconvex costs, marginal cost prices may not cover the total cost of starting the generator and running at the efficient output level. Uplift payments cover the difference. The PJM market design concept incorporates efficient prices with minimal uplift payments.

But PJM's practice does not minimize uplift payments. In some cases, PJM pays uplift that is not consistent with the rules. In some cases, the rules permit the payment of uplift that is not consistent with the goal of PJM market design. There are identified improvements to PJM's application of the rules, and to the market design and uplift rules that could reduce uplift payments to the efficient level.

PJM's day-ahead generator credits and balancing generator credits are calculated by operating day and by operating segment. Segments for day-ahead generator credits equal the hours in which the unit cleared in the day-ahead market. Segments for balancing generator credits are defined as the greater of the day-ahead schedule and the unit's minimum run time. Intervals in excess of the minimum run time or in excess of the hours cleared in the day-ahead market become new segments.

In PJM, all energy payments to demand response resources are uplift payments. The energy payments to these resources are not part of the supply and demand balance, they are not paid by LMP revenues and therefore the energy payments to demand response resources have to be paid as out of market uplift. The energy payments to economic DR are funded by real-time load and real-time exports. The energy payments to emergency DR are funded by participants with net energy purchases in the real-time energy market. The current payment structure for DR is an inefficient element of the PJM market design.[4]

1 Losses occur when gross energy and ancillary services market revenues are less than short run marginal costs, including all elements of the energy offer, which are startup, no load and incremental offers, and the unit is following PJM instructions including both commitment and dispatch instructions. There is no corresponding assurance required when units are self scheduled or not following PJM dispatch instructions.

2 *See* Stoft, *Power System Economics: Designing Markets for Electricity*, New York: Wiley (2002) at 272; Mas-Colell, Whinston, and Green, *Microeconomic Theory*, New York: Oxford University Press (1995) at 570; and Quinzii, *Increasing Returns and Efficiency*, New York: Oxford University Press (1992).

3 The production of output is convex if the production function has constant or decreasing returns to scale, which result in constant or rising average costs with increases in output. Production is nonconvex with increasing returns to scale, which is the case when generating units have start or no load costs that are large relative to marginal costs. *See* Mas-Colell, Whinston, and Green at 132.

4 Demand response payments are addressed in Section 6: Demand Response.

Overview

Energy Uplift Credits

- **Energy uplift credits.** Total energy uplift credits decreased by $8.6 million, or 30.5 percent, in the first three months of 2023 compared to the same time period in 2022, from $28.2 million to $19.6 million.
- **Types of energy uplift credits.** In the first three months of 2023, total energy uplift credits included $4.0 million in day-ahead generator credits, $11.7 million in balancing generator credits, $3.5 million in lost opportunity cost credits, and $0.1 million in local constraint control credits. Dispatch differential lost opportunity credits, which are a subset of balancing operating reserves, were implemented as part of fast start pricing on September 1, 2021, and were $0.1 million in the first three months of 2023. Regulation revenues should be included as an offset to uplift, but are not currently included.
- **Types of units.** In the first three months of 2023, coal units received 82.1 percent of day-ahead generator credits, and combustion turbines received 71.1 percent of balancing generator credits and 90.6 percent of lost opportunity cost credits. Combined cycle units and combustion turbines received 53.4 percent of dispatch differential lost opportunity credits.
- **Day-ahead unit commitment for reliability.** In the first three months of 2023, less than 1.0 percent of the total day-ahead generation MWh was scheduled as must run for reliability by PJM, of which 84.0 percent received energy uplift payments.
- **Concentration of energy uplift credits.** In the first three months of 2023, the top 10 units receiving energy uplift credits received 20.8 percent of all credits and the top 10 organizations received 42.3 percent of all credits. The HHI for day-ahead operating reserves was 8906, the HHI for balancing generator credits was 3055 and the HHI for lost opportunity cost was 5755, all of which are classified as highly concentrated.
- **Lost opportunity cost credits.** Lost opportunity cost credits decreased by $2.5 million, or 41.2 percent, in the first three months of 2023, compared to the same time period in 2022, from $6.6 million to $3.5 million. Some combustion turbines and diesels are scheduled day-ahead but not requested in real time, and receive day-ahead lost opportunity cost credits as a result. This was the source of 90.2 percent of the $3.5 million.
- **Following dispatch.** Some units are incorrectly paid uplift despite not meeting uplift eligibility requirements, including not following dispatch, not having the correct commitment status, or not operating with PLS offer parameters. Since 2018, the MMU has made cumulative resettlement requests for the most extreme overpaid units of $15.1 million, of which PJM has resettled only $1.4 million over the last two years, or 9.2 percent.
- **Daily uplift.** In the first three months of 2023, balancing generator charges would have been $1.9 million or 16.7 percent lower if they had been calculated on a daily basis rather than a segmented basis. Uplift was designed to be charged on a daily basis and not on an intraday segmented basis.
- **CT uplift exemption:** The rule that allowed CTs to be paid uplift regardless of how well they followed dispatch was terminated on November 1, 2022. Starting November 1, 2022, CTs are paid uplift if necessary to cover costs based on the lower of actual or desired output (as calculated by PJM based on the dispatch signal), like all other unit types.

Energy Uplift Charges

- **Energy Uplift Charges.** Total energy uplift charges (equal to total energy uplift credits) decreased by $8.6 million, or 30.5 percent, in the first three months of 2023 compared to the same time period in 2022, from $28.2 million to $19.6 million.
- **Types of Energy Uplift Charges.** In the first three months of 2023, total uplift charges included $4.0 million in day-ahead operating reserve charges, $15.4 million in balancing generator charges, and $0.1 million in black start services.
- **UTC Uplift.** Effective November 1, 2020, UTC transactions are allocated day-ahead and real-time uplift charges on a basis equivalent to a decrement bid (DEC) at the sink point of the UTC.[5]

5 See 172 FERC ¶ 61,046 (2020).

- **Average Effective Operating Reserve Rates in the Eastern Region.** Day-ahead load, exports, DECs and UTCs paid $0.016 per MWh in the Eastern Region. Real-time load and exports paid an average of $0.048 per MWh. Deviations paid $0.089 per MWh in the Eastern Region.
- **Average Effective Operating Reserve Rates in the Western Region.** Day-ahead load, exports, DECs and UTCs paid $0.016 per MWh in the Western Region. Real-time load and exports paid $0.031 per MWh. Deviations paid $0.068 per MWh in the Western Region.

Geography of Charges and Credits

- In the first three months of 2023, 89.4 percent of all uplift charges allocated regionally (day-ahead operating reserves and balancing generator credits) were paid by MW at control zones, 3.3 percent by MW at hubs and aggregates, and 7.3 percent by MW at interchange interfaces.
- In the first three months of 2023, generators in the Eastern Region received 52.5 percent of all balancing generator credits, including lost opportunity cost and canceled resources credits.
- In the first three months of 2023, generators in the Western Region received 46.4 percent of all balancing generator credits, including lost opportunity cost and canceled resources credits.
- In the first three months of 2023, external pseudo tied generators received 1.1 percent of all balancing generator credits, including lost opportunity cost and canceled resources credits.

Recommendations

- The MMU recommends that uplift be paid only based on operating parameters that reflect the flexibility of the benchmark new entrant unit (CONE unit) in the PJM Capacity Market. (Priority: High. First reported 2018. Status: Not adopted.)
- The MMU recommends that PJM not pay uplift to units not following dispatch, including uplift related to fast start pricing, and require refunds where it has made such payments. This includes units whose offers are flagged for fixed generation in Markets Gateway because such units are not dispatchable. (Priority: Medium. First reported 2018. Status: Not adopted.)
- The MMU recommends that PJM pay uplift based on the offer at the lower of the actual unit output or the dispatch signal MW. (Priority: Medium. First reported 2018. Status: Not adopted.)
- The MMU recommends eliminating intraday segments from the calculation of uplift payments and returning to calculating the need for uplift based on the entire 24 hour operating day. (Priority: High. First reported 2018. Status: Not adopted.)
- The MMU recommends the elimination of day-ahead uplift to ensure that units receive an energy uplift payment based on their real-time output and not their day-ahead scheduled output. (Priority: Medium. First reported 2013. Status: Not adopted.)
- The MMU recommends that units not be paid lost opportunity cost uplift credits when PJM directs a unit to reduce output based on a transmission constraint or other reliability issue. There is no lost opportunity because the unit is required to reduce for the reliability of the unit and the system. (Priority: High. First reported 2021. Status: Not adopted.)
- The MMU recommends reincorporating the use of net regulation revenues as an offset in the calculation of balancing generator credits. (Priority: Medium. First reported 2009. Status: Not adopted.)
- The MMU recommends that self scheduled units not be paid energy uplift credits for their startup cost when the units are scheduled by PJM to start before the self scheduled hours. (Priority: Low. First reported 2013. Status: Not adopted.)
- The MMU recommends three modifications to the energy lost opportunity cost calculations:
  - The MMU recommends calculating LOC based on 24 hour daily periods for combustion turbines and diesels scheduled in the day-ahead energy market, but not committed in real time. (Priority: Medium. First reported 2014. Status: Not adopted.)

  - The MMU recommends that units scheduled in the day-ahead energy market and not committed in real time should be compensated for LOC based on their real-time desired and achievable output, not their scheduled day-ahead output. (Priority: Medium. First reported 2015. Status: Not adopted.)
  - The MMU recommends that only flexible fast start units (startup plus notification times of 10 minutes or less) and units with short minimum run times (one hour or less) be eligible by default for the LOC compensation to units scheduled in the day-ahead energy market and not committed in real time. Other units should be eligible for LOC compensation only if PJM explicitly cancels their day-ahead commitment. (Priority: Medium. First reported 2015. Status: Not adopted.)
- The MMU recommends that up to congestion (UTC) transactions be required to pay energy uplift charges for both the injection and the withdrawal sides of the UTC. (Priority: High. First reported 2011. Status: Partially adopted.)
- The MMU recommends allocating the energy uplift credits paid to units scheduled by PJM as must run in the day-ahead energy market for reasons other than voltage/reactive or black start services as a reliability charge to real-time load, real-time exports and real-time wheels. (Priority: Medium. First reported 2014. Status: Not adopted. Stakeholder process.)
- The MMU recommends that the total cost of providing reactive support be categorized and allocated as reactive services. Reactive services credits should be calculated consistent with the balancing generator credit calculation. (Priority: Medium. First reported 2012. Status: Not adopted. Stakeholder process.)
- The MMU recommends including real-time exports and real-time wheels in the allocation of the cost of providing reactive support to the 500 kV system or above, in addition to real-time load. (Priority: Low. First reported 2013. Status: Not adopted.)
- The MMU recommends modifications to the calculation of lost opportunity costs credits paid to wind units. The lost opportunity costs credits paid to wind units should be based on the lesser of the desired output, the estimated output based on actual wind conditions and the capacity interconnection rights (CIRs). The MMU recommends that PJM allow wind units to request CIRs that reflect the maximum output wind units want to inject into the transmission system at any time. (Priority: Low. First reported 2012. Status: Partially adopted.)
- The MMU recommends that PJM clearly identify and classify all reasons for incurring uplift in the day-ahead and the real-time energy markets and the associated uplift charges in order to make all market participants aware of the reasons for these costs and to help ensure a long term solution to the issue of how to allocate the costs of uplift. (Priority: Medium. First reported 2011. Status: Partially adopted.)
- The MMU recommends that PJM revise the current uplift confidentiality rules in order to allow the disclosure of complete information about the level of uplift by unit and the detailed reasons for the level of uplift credits by unit in the PJM region. (Priority: High. First reported 2013. Status: Partially adopted.)[6]
- The MMU recommends that PJM eliminate the exemption for CTs and diesels from the requirement to follow dispatch in order to receive uplift. The performance of these resources should be evaluated in a manner consistent with all other resources (Priority: Medium. First reported 2018. Status: Adopted 2022.)

Conclusion

Competitive market outcomes result from energy offers equal to short run marginal costs that incorporate flexible operating parameters. When PJM permits a unit to include inflexible operating parameters in its offer and pays uplift based on those inflexible parameters, there is an incentive for the unit to remain inflexible. The rules regarding operating parameters should be implemented in a way that creates incentives for flexible operations rather than inflexible operations. The standard for paying uplift should be the maximum achievable flexibility, based on OEM standards for the benchmark new entrant

6 On September 7, 2018, PJM made a compliance filing for FERC Order No. 844 to publish unit specific uplift credits. The compliance filing was accepted by FERC on June 21, 2019. 166 FERC ¶ 61,210 (2019). PJM began posting unit specific uplift reports on May 1, 2019. 167 FERC ¶ 61,280 (2019).

unit (CONE unit) in the PJM Capacity Market demand (VRR) curve. Applying a weaker standard effectively subsidizes inflexible units by paying them based on inflexible parameters that result from lack of investment and that could be made more flexible. The result inflates uplift costs, suppresses energy prices, and is an incentive to inflexibility.

It is not appropriate to accept that inflexible units should be paid uplift based on inflexible offers. The question of why units make inflexible offers should be addressed directly. Are units inflexible because they are old and inefficient, because owners have not invested in increased flexibility or because they serve as a mechanism for the exercise of market power? The question of why the inflexible unit was built, whether it was built under cost of service regulation and whether it is efficient to retain the unit should be answered directly. The question of how to provide market incentives for investment in flexible units and for investment in increased flexibility of existing units should be addressed directly. The question of whether inflexible units should be paid uplift at all should be addressed directly. Marginal cost pricing without paying uplift to inflexible units would create incentives for market participants to provide flexible solutions including replacing inefficient units with flexible, efficient units.

Implementing combined cycle modeling, to permit the energy market model optimization to take advantage of the versatility and flexibility of combined cycle technology in commitment and dispatch, would provide significant flexibility without requiring a distortion of the market rules. But such modeling should not be used as an excuse to eliminate market power mitigation or an excuse to permit inflexible offers to be paid uplift. There are defined steps that could and should be taken immediately to improve the modeling of combined cycle plants that do not require investment in combined cycle modeling software, including modeling soak time, and accurately accounting for transition times to power augmentation offer segments.

The reduction of uplift payments should not be a goal to be achieved at the expense of the fundamental logic of the LMP system. For example, the use of closed loop interfaces to reduce uplift should be eliminated because it is not consistent with LMP fundamentals and constitutes a form of subjective price setting. The same is true of what PJM terms its CT price setting logic. The same is true of fast start pricing. The same is true of PJM's proposal to modify the ORDC in order to increase energy prices and reduce uplift.

Accurate short run price signals, equal to the short run marginal cost of generating power, provide market incentives for cost minimizing production to all economically dispatched resources and provide market incentives to load based on the marginal cost of additional consumption. The objective of efficient short run price signals is to minimize system production costs, not to minimize uplift. Repricing the market to reflect commitment costs will create a tradeoff between minimizing production costs and reduction of uplift. The tradeoff will exist because when commitment costs are included in prices, the price signal no longer equals the short run marginal cost and therefore no longer provides the correct signal for efficient behavior for market participants making decisions on the margin, whether resources, load, interchange transactions, or virtual traders. This tradeoff now exists based on PJM's recently implemented fast start pricing proposal (limited convex hull pricing). Fast start pricing was approved by FERC and implemented on September 1, 2021.[7] Fast start pricing affects uplift calculations by introducing a new category of uplift in the balancing market, and changing the calculation of uplift in the day-ahead market.

When units receive substantial revenues through energy uplift payments, these payments are not fully transparent to the market, in part because of the current confidentiality rules. As a result, other market participants, including generation and transmission developers, do not have the opportunity to compete to displace them. As a result, substantial energy uplift payments to a concentrated group of units and organizations have persisted. FERC Order No. 844 authorized the publication of unit specific uplift payments for credits incurred after July 1, 2019.[8] However, Order No. 844 failed to require the publication of unit specific uplift credits for the largest units receiving significant uplift payments, inflexible steam units committed for reliability in the day-ahead market.

7 See 173 FERC ¶ 61,244 (2020).

8 On June 21, 2019, FERC accepted PJM's Order No. 844 compliance filing. 166 FERC ¶ 61,210 (2019). The filing stated that PJM would begin posting unit specific uplift reports on May 1, 2019. On April 8, 2019, PJM filed for an extension on the implementation date of the zonal uplift reports and unit specific uplift reports to July 1, 2019. On June 28, 2019, FERC accepted PJM's request for extension of effective dates. 167 FERC ¶ 61,280 (2019).

Uplift payments could be significantly reduced by reversing many of the changes that have been made to the original basic uplift rules. The goal of uplift is to ensure that competitive energy and ancillary service market outcomes do not require efficient resources operating for the PJM system, at the direction of PJM, to operate at a loss. In the original PJM design, uplift was calculated on a daily basis, including all costs and net revenues. But that rule was changed to use only segments of the day. The result is to overstate uplift payments because units may be paid uplift for a day in which their net revenues exceed their costs. In the original PJM design, all net revenues from energy and ancillary services were an offset to uplift payments. But that rule was changed to eliminate net revenue from the regulation market. The result is to overstate uplift payments, for no logical reason.

Uplift payments could also be significantly reduced to a more efficient level by eliminating all day-ahead operating reserve credits. It is illogical and unnecessary to pay units day-ahead operating reserve credits because units do not incur any costs to run and any revenue shortfalls are addressed by balancing generator credits.

On July 16, 2020, following its investigation of the issue, the Commission ordered PJM to revise its rules so that UTCs are required to pay uplift on the withdrawal side (DEC) only.[9] The uplift payments for UTCs began on November 1, 2020. The MMU has had a longstanding recommendation that UTCs be required to pay uplift on both the injection and withdrawal sides.[10]

On November 1, 2022, the longstanding rule which exempted CTs from the otherwise generally applicable rules governing the payment of uplift credits, was terminated.[11] Prior to November 1, CTs were paid uplift regardless of their output and regardless of whether they followed dispatch. As a result of the rule, CTs had no incentive to follow PJM dispatch signals and received excessive uplift credits.

9 See 172 FERC ¶ 61,046 (2020).
10 On October 17, 2017, PJM filed a proposed tariff change at FERC to allocate uplift to UTC transactions in the same way uplift is allocated to other virtual transactions, as a separate injection and withdrawal deviation. FERC rejected the proposed tariff change. See 162 FERC ¶ 61,019 (2018).
11 See PJM "Manual 28: Operating Reserve Accounting," Rev. 88 (Oct. 1, 2022).

The rule change is expected to reduce balancing generator reserve credits paid to combustion turbines and diesel engines. The rule change is expected to have no impact on lost opportunity cost credits, dispatch differential lost opportunity cost credits, reactive service credits, and black start credits, despite CTs also receiving a large share of those credit categories. No is expected to these categories because the calculation for these credit categories is not based on distinguishing the PJM calculated desired MW from the actual generation.

PJM needs to pay substantially more attention to the details of uplift payments including accurately tracking whether units are following dispatch, identifying the actual need for units to be dispatched out of merit and determining whether better definitions of constraints would be a more market based approach. PJM pays uplift to units even when they do not operate as requested by PJM, i.e. when units do not follow dispatch. PJM uses dispatcher logs as a primary screen to determine if units are eligible for uplift regardless of how they actually operate or if they followed the PJM dispatch signal. The reliance on dispatcher logs for this purpose is impractical, inefficient, and incorrect. PJM needs to define and implement systematic and verifiable rules for determining when units are following dispatch as a primary screen for eligibility for uplift payments. PJM should not pay uplift to units that do not follow dispatch.

The MMU notifies PJM and generators of instances in which, based on the PJM dispatch signal and the real-time output of the unit, it is clear that the unit did not operate as requested by PJM. The MMU sends requests for resettlements to PJM to make the units with the most extreme overpayments ineligible for uplift credits. Since 2018, the MMU has requested that PJM require the return of $15.1 million of incorrect uplift credits of which PJM has resettled only $1.4 million over the last two years, or 9.2 percent. In addition, PJM has refused to accept the return of incorrectly paid uplift credits by generators when the MMU has identified such cases.

While energy uplift charges are an appropriate part of the cost of energy, market efficiency would be improved by ensuring that the level and variability of these charges are as low as possible consistent with the reliable operation of the system and consistent with pricing at short run marginal cost. The goal should be to minimize the total incurred energy uplift charges and to increase the transactions over which those charges are spread in order to reduce the impact of energy uplift charges on markets. The result would be to reduce the level of per MWh charges, to reduce the uncertainty associated with uplift charges and to reduce the impact of energy uplift charges on decisions about how and when to participate in PJM markets. The result would also be to increase incentives for flexible operation and to decrease incentives for the continued operation of inflexible and uneconomic resources. PJM does not need a new flexibility product. PJM needs to provide incentives to existing and new entrant resources to unlock the significant flexibility potential that already exists, to end incentives for inflexibility and to stop creating new incentives for inflexibility.

Energy Uplift Credits

The level of energy uplift credits paid to specific units depends on the level of the resource's energy offer, the LMP, the resource's operating parameters and the decisions of PJM operators. Energy uplift credits result in part from decisions by PJM operators, who follow reliability requirements and market rules, to start resources or to keep resources operating even when LMP is less than the offer price including incremental, no load and startup costs. Energy uplift payments also result from units' operational parameters that require PJM to schedule or commit resources when they are not economic. Energy uplift payments currently also result, incorrectly, from decisions by units to maintain an output level not consistent with PJM dispatch instructions. The resulting costs not covered by energy revenues are collected as energy uplift.

The day-ahead operating reserves category includes multiple credit types that are paid to resources cleared uneconomically in the day-ahead market. These resources include generators, imports, and load response. The balancing operating reserves category includes multiple credit types based on the service provided by the resources. These credit types, paid to compensate for uneconomic generation in the balancing market, include generator credits, lost opportunity cost credits, dispatch differential cost credits, local constraints control credits, load response credits, import credits, and canceled resource credits. The largest credit type in the balancing operating reserves category is balancing generator credits. The reactive services category includes multiple credit types. Black start services credits exist to compensate resources for black start services in the day-ahead and balancing markets, as well as testing.

Table 4-1 shows the totals for each credit category during the first three months of 2022 and 2023.[12] In the first three months of 2023, energy uplift credits decreased by $8.6 million or 30.5 percent compared to the same time period in 2022.

The dispatch differential lost opportunity cost is a credit paid to resources that, in order to accommodate inflexible fast start resources, are dispatched down to an output below the level that is economic for them at the market prices that result from fast start pricing. Fast start pricing was introduced on September 1, 2021, and with it the dispatch differential lost opportunity cost credit.

12 Billing data can be modified by PJM Settlements at any time to reflect changes in the evaluation of energy uplift. The billing data reflected in this report were current on April 17, 2023.

Table 4-1 Energy uplift credits by category: January through March, 2022 and 2023[13]

Category	Type	(Jan - Mar) 2022 Credits (Millions)	(Jan - Mar) 2023 Credits (Millions)	Change	Percent Change	2022 Share	2023 Share
	Generators	$1.7	$4.0	$2.3	136.4%	6.1%	20.6%
	Imports	$0.0	$0.0	($0.0)	(100.0%)	0.0%	0.0%
Day-Ahead	Load Response	$0.0	$0.0	$0.0	NA	0.0%	0.0%
	Canceled Resources	$0.0	$0.0	$0.0	NA	0.0%	0.0%
	Generators	$18.7	$11.7	($7.0)	(37.6%)	66.4%	59.6%
	Imports	$0.0	$0.0	$0.0	NA	0.0%	0.0%
	Load Response	$0.0	$0.0	$0.0	NA	0.0%	0.0%
	Local Constraints Control	$1.1	$0.1	($1.0)	(89.1%)	3.9%	0.6%
	Lost Opportunity Cost	$6.0	$3.5	($2.5)	(41.2%)	21.1%	17.9%
Balancing	Dispatch Differential Lost Opportunity Cost	$0.3	$0.1	($0.2)	(100.0%)	(100.0%)	0.7%
	Day-Ahead	$0.0	$0.0	$0.0	NA	0.0%	0.0%
	Local Constraints Control	$0.0	$0.0	$0.0	NA	0.0%	0.0%
	Lost Opportunity Cost	$0.0	$0.0	($0.0)	(100.0%)	0.0%	0.0%
	Reactive Services	$0.2	$0.0	($0.2)	(100.0%)	0.8%	0.0%
Reactive Services	Synchronous Condensing	$0.0	$0.0	$0.0	NA	0.0%	0.0%
Synchronous Condensing		$0.0	$0.0	$0.0	NA	0.0%	0.0%
	Day-Ahead	$0.0	$0.0	$0.0	NA	0.0%	0.0%
	Balancing	$0.0	$0.0	$0.0	NA	0.0%	0.0%
Black Start Services	Testing	$0.1	$0.1	($0.0)	(13.0%)	0.4%	0.6%
Total		$28.2	$19.6	($8.6)	(30.5%)	100.0%	100.0%

Credits and Charges Categories

Energy uplift charges include day-ahead and balancing operating reserves, reactive services, synchronous condensing and black start services categories. Uplift credits paid to individual participants are paid for by charges to the groups of PJM market participants. The groups of participants charged varies depending on the type of uplift credit. Table 4-2 and Table 4-3 show the categories of credits and charges and their relationships.

For example, in Table 4-2, day-ahead operating reserve credits for generators are paid for by day-ahead operating reserve charges. Those charges are paid for by PJM members in proportion to their day-ahead load, day-ahead exports, virtual transactions (DECs and UTCs). The charges are aggregated over the entire RTO region. Balancing generator reserve credits are paid for by two different types of charges: balancing operating reserve charges for reliability and balancing operating reserve charges for deviations. Charges for reliability are paid for by PJM members in proportion to their real-time load and real-time export transactions. Reliability charges are aggregated regionally over the entire RTO region, within the Western region, or within the Eastern region. Balancing operating reserve charges for deviations are paid for by PJM members in proportion to their deviations, which includes virtuals (INCs and DECs), UTCs, load, and interchange. The deviation charges are aggregated regionally over the entire RTO region, within the Western region, and within the Eastern region. Lost opportunity cost credits are paid for by balancing operating reserve charges for deviations. The charges for deviations are paid for by PJM members in proportion to their deviations, which includes virtuals (INCs and DECs), UTCs, load, and interchange. The deviation charges are aggregated regionally over the entire RTO region.

13 Year to year change is rounded to one tenth of a million, and includes values less than $0.05 million.

Table 4-3 shows the relationship between credits and charges for resources providing reactive, synchronous condensing, and black start services. For example, the five sub-categories of reactive services credits (day-ahead operating reserves, generator, LOC, condensing, and synchronous condensing LOC) are paid by two different charge categories: reactive service charges and local constraint reactive services. The reactive service charges are paid by PJM members in proportion to their zonal real-time load, while the local constraint reactive service charges are paid for by transmission owners.

Table 4-2 Day-ahead and balancing operating reserve credits and charges

	Credit Category	Charges Category	Charge Responsibility	Geographic Charge Aggregation
DAY-AHEAD	Day-Ahead Operating Reserve Transaction	Day-Ahead Operating Reserves for Transactions	Day-Ahead Load, Day-Ahead Exports, DECs & UTCs	RTO Region
	Day-Ahead Operating Reserve Generator	Day-Ahead Operating Reserve for Generators		
	Day-Ahead Operating Reserves for Load Response	Day-Ahead Operating Reserve for Load Response		
	Unallocated Negative Load Congestion Charges Unallocated Positive Generation Congestion Credits	Unallocated Congestion		
BALANCING	Balancing Generator Reserves	Balancing Operating Reserve for Reliability	Real-Time Load plus Real-Time Export Transactions	RTO, Eastern, and Western Region
		Balancing Operating Reserve for Deviations	Deviations (includes virtual bids, UTCs, load, and interchange)	
	Dispatch Differential Lost Opportunity Cost (DDLOC)	Balancing Operating Reserve for Deviations	Real-Time Load plus Real-Time Export Transactions	RTO Region
	Canceled Resources	Balancing Operating Reserve for Deviations	Deviations (includes virtual bids, UTCs, load, and interchange)	
	Lost Opportunity Cost (LOC)			
	Real-Time Import Transactions			
	Balancing Operating Reserves for Load Response	Balancing Operating Reserve for Load Response	Deviations (includes virtual bids, UTCs, load, and interchange)	
	Local Constraints Control	NA	Transmission Owner	NA

Table 4-3 Reactive services, synchronous condensing and black start services credits and charges

	Credits Category	Charges Category	Charge Responsibility
Reactive	Day-Ahead Operating Reserve	Reactive Services Charge	Zonal Real-Time Load
	Generator Reactive Services		
	LOC Reactive Services		
	Condensing Reactive Services	Local Constraint Reactive Services	Transmission owner
	Synchronous Condensing LOC Reactive Services		
Synchronous Condensing	Synchronous Condensing	Synchronous Condensing	Real-Time Load
	Synchronous Condensing LOC		Real-Time Export Transactions
Black Start	Day-Ahead Operating Reserve	Black Start Service Charge	Zone/Non-zone Peak Transmission Use and Point to Point Transmission Reservations
	Balancing Operating Reserve		
	Black Start Testing		

Types of Units

Table 4-4 shows the distribution of total energy uplift credits by unit type during the first three months of 2022 and 2023. A combination of factors led to overall decreased uplift payments.

The longstanding rule which inexplicably exempted CTs from the otherwise generally applicable rules governing the payment of uplift credits, was terminated effective November 1, 2022. Prior to November 1, CTs were paid uplift regardless of their output and regardless of whether they followed dispatch and as a result, CTs had no incentive to follow PJM dispatch signals.

Uplift credits paid to combustion turbines decreased by $11.3 million or 49.7 percent in the first three months of 2023 compared to the same time period in2022. In the first three months of 2023, CTs received 84.5 percent of lost opportunity cost credits, a decrease of $2.5 million or 41.2 percent compared to the same time period in 2022.

Uplift credits paid to steam coal units increased by $2.4 million or 134.7 percent during 2022 compared to the same time period in 2022. In the first three months of 2023, day-ahead uplift credits for reliability totaled $3.9 million, compared to $0.6 million during the same time period in 2022. In the first three months of 2023, day-ahead credits for reliability in the BGE, PPL, and PEPCO Zones made up 95.9 percent of total day-ahead credits for reliability. Reliability needs in the BGE and PEPCO Zones are the result of recurrent N-1-1 contingencies in the BGE and PEPCO Zones. A small number of coal units committed for reliability in the BGE Zones received 83.7 percent of day-ahead credits, and this was the main cause of the increase in day-ahead credits.

Uplift credits paid to other (gas or oil fired) steam units increased by $0.9 million or 372.6 percent during the first three months of 2023 compared to the same time period in. The increase in balancing generator credits to gas or oil fired steam units was due to a small number of units in the BGE Zone. Gas or oil fired steam units were responsible for 18.0 percent of the increase in day-ahead credits during the first three months of 2023 compared to the same time period in 2022. In the first three months of 2023, gas or oil fired steam units received $1.2 million, or 6.0 percent of total credits, compared to $0.3 million and 0.9 percent during the same time period in 2022. The increase in day ahead operating reserve payments to gas or oil fired steam units was due to a small number of units in the PEPCO Zone.

Uplift credits paid to combined cycle units decreased by $1.9 million or 70.4 percent during the first three months of 2023 compared to the same time period in 2022.

In the first three months of 2023, uplift credits to wind units were $0.4 million, up by 1,080.6 percent compared to the same time period in 2022.

Table 4-4 Total energy uplift credits by unit type: January through March, 2022 and 2023[14] [15]

Unit Type	(Jan - Mar) 2022 Credits (Millions)	(Jan - Mar) 2023 Credits (Millions)	Change	Percent Change	(Jan - Mar) 2022 Share	(Jan - Mar) 2023 Share
Combined Cycle	$2.8	$0.8	($1.9)	(70.4%)	9.8%	4.2%
Combustion Turbine	$22.7	$11.4	($11.3)	(49.7%)	80.5%	58.2%
Diesel	$0.7	$1.6	$0.9	136.6%	2.4%	8.3%
Hydro	$0.0	$0.0	$0.0	0.0%	0.0%	0.0%
Nuclear	$0.0	$0.0	($0.0)	(93.0%)	0.0%	0.0%
Solar	$0.0	$0.0	($0.0)	(100.0%)	0.0%	0.0%
Steam - Coal	$1.8	$4.1	$2.4	134.7%	6.2%	21.1%
Steam - Other	$0.3	$1.2	$0.9	372.6%	0.9%	6.0%
Wind	$0.0	$0.4	$0.4	1,080.6%	0.1%	2.2%
Total	$28.2	$19.6	($8.6)	(30.5%)	100.0%	100.0%

Table 4-5 shows the distribution of energy uplift credits by category and by unit type in the first three months of 2023. The largest share of day-ahead credits, 82.1 percent, went to steam units because steam units tend to be longer lead time units that are committed before the operating day. If a steam unit is needed for reliability and it is uneconomic, it will be committed in the day-ahead energy market and receive day-ahead uplift credits. The PJM market rules permit combustion turbines (CT), unlike other unit types, to be committed and decommitted in the real-time market. As a result of the rules and the characteristics of CT offers, CTs received 71.1 percent of balancing

14 Table 4-2 does not include balancing imports credits and load response credits in the total amounts.

15 Solar units should be ineligible for all uplift payments because they do not follow PJM's dispatch instructions. The MMU notified PJM of the discrepancy.

credits and 84.5 percent of lost opportunity cost credits. Combustion turbines committed in the real-time market may be paid balancing credits due to inflexible operating parameters, volatile real-time LMPs, and intraday segment settlements. Combustion turbines committed in the day-ahead market but not committed in real time receive lost opportunity credits to cover the profits they would have made had they operated in real time.

Table 4-5 Energy uplift credits by unit type: January through March, 2023[16]

Unit Type	Day-Ahead Generator	Balancing Generator	Canceled Resources	Local Constraints Control	Lost Opportunity Cost	Reactive Services	Synchronous Condensing	Black Start Services	Dispatch Differential Lost Opportunity Cost
Combined Cycle	2.5%	5.6%	0.0%	0.0%	0.1%	0.0%	0.0%	0.0%	42.0%
Combustion Turbine	0.5%	71.1%	0.0%	0.0%	84.5%	0.0%	0.0%	99.8%	11.4%
Diesel	0.0%	11.9%	0.0%	14.0%	6.1%	0.0%	0.0%	0.2%	0.4%
Hydro	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.3%
Nuclear	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Solar	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Steam - Coal	82.1%	6.4%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	41.7%
Steam - Other	14.9%	4.9%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	2.8%
Wind	0.0%	0.0%	0.0%	86.0%	9.4%	0.0%	0.0%	0.0%	1.4%
Total (Millions)	$4.0	$11.7	$0.0	$0.1	$3.5	$0.0	$0.0	$0.1	$0.1

Day-Ahead Unit Commitment for Reliability

PJM can schedule units as must run in the day-ahead energy market that would otherwise not have been committed in the day-ahead market, when needed in real time to address reliability issues. Such reliability issues include thermal constraints, reactive transfer interface constraints, and reactive service.[17] Participants can submit units as self scheduled (must run), meaning that the unit must be committed, but a unit submitted as self scheduled by a participant is not eligible for day-ahead operating reserve credits.[18] Units committed for reliability by PJM are eligible for day-ahead operating reserve credits and may set LMP if raised above economic minimum and follow the dispatch signal.

Table 4-6 shows total day-ahead generation and day-ahead generation committed for reliability by PJM. Day-ahead generation committed for reliability by PJM increased by 569.0 percent during the first three months of 2023 compared to 2022, from 41.2 GWh during the first three months of 2022 to 275.3 GWh during the first three months of 2023. The increase in day-ahead generation committed for reliability by PJM was the result of a need for reliability, primarily in the BGE Zone.

16 The data in the Uplift section of the *2022 State of the Market Report for PJM* includes incorrect data for the dispatch differential lost opportunity cost credit that PJM recalculated too late (February 27) for inclusion in the tables and figures.
17 See OA Schedule 1 § 3.2.3(b).
18 See OA Schedule 1 § 3.2.3(a).

Table 4-6 Day-ahead generation committed for reliability (GWh): January 2022 through March 2023

	2022			2023			
	Total Day-Ahead Generation (GWh)	Day-Ahead PJM Must Run Generation (GWh)	Share	Total Day-Ahead Generation (GWh)	Day-Ahead PJM Must Run Generation (GWh)	Share	Percent Change of PJM Day-Ahead Must Run Generation
Jan	81,373	0	0.0%	213,371	90	0.0%	NA
Feb	68,253	37	0.1%	190,424	101	0.1%	170.0%
Mar	66,579	4	0.0%	201,718	85	0.0%	2,203.1%
Apr	57,663	8	0.0%				NA
May	63,309	389	0.6%				NA
Jun	70,849	417	0.6%				NA
Jul	81,815	594	0.7%				NA
Aug	80,627	432	0.5%				NA
Sep	67,871	378	0.6%				NA
Oct	59,982	0	0.0%				NA
Nov	62,046	49	0.1%				NA
Dec	74,777	477	0.6%				NA
Total (Jan - Mar)	216,205	41	0.0%	605,513	275	0.0%	569.0%
Total	835,145	2,785	0.3%	605,513	275	0.0%	569.0%

Pool scheduled units are units committed by PJM. Self scheduled units are self committed by the generation owner. Units committed for reliability by PJM are units that are committed in the day-ahead energy market, regardless of whether the offers are economic. Both types of units are made whole in the day-ahead energy market if their total cost-based offer (including no load and startup costs) is greater than the revenues from the day-ahead energy market. Such units are paid day-ahead uplift (operating reserve credits). Total day-ahead operating reserve credits in the first three months of 2023 were $4.0 million, of which $3.9 million or 95.9 percent was paid to units committed for reliability by PJM, and not scheduled to provide reactive services. There were no additional day-ahead operating reserves paid to units scheduled to provide reactive services. The top 10 units received $4.0 million or 98.8 percent of all day-ahead operating reserve credits. These units were large units with operating parameters less flexible than PLS parameters, including long minimum run times.

It is illogical and unnecessary to pay units day-ahead operating reserves because units do not incur any costs to run in the day-ahead market and any revenue shortfalls are addressed by balancing operating reserve payments.

Table 4-7 shows the total day-ahead generation committed for reliability by PJM by category. In the first three months of 2023, 84.0 percent of the day-ahead generation committed for reliability by PJM was paid day-ahead operating reserve credits. The remaining 16.0 percent of the day-ahead generation committed for reliability was economic, meaning that the generation was not paid operating reserve credits because prices covered the generators' offers.

Table 4-7 Day-ahead generation committed for reliability by category (GWh): January through March, 2023

	Reactive Services (GWh)	Day-Ahead Operating Reserves (GWh)	Economic (GWh)	Total (GWh)
Jan	0.0	71.8	17.8	89.6
Feb	0.0	101.2	0.0	101.2
Mar	0.0	58.4	26.2	84.6
Total (Jan - Mar)	0.0	231.4	43.9	275.3
Share	0.0%	84.0%	16.0%	100.0%

Balancing Operating Reserve Credits/Balancing Generator Credits

Balancing operating reserve (BOR) credits are paid to resources that operate as requested by PJM that do not recover all of their operating costs from market revenues. The category of balancing operating reserves includes multiple credit types that are paid to units operating uneconomically in the balancing market, such as generator credits, lost opportunity cost credits, dispatch differential cost credits, local constraints control credits, load response credits, import credits, and canceled resource credits. The largest category of balancing operating reserves are the balancing generator credits.. Balancing generator credits are calculated by segment as the difference between a resource's revenues (day-ahead market, balancing market, reserve markets, reactive service credits, and day-ahead operating reserve credits but excluding regulation revenues) and its real-time offer (startup, no load, and incremental energy offer). Segments for balancing generator credits are defined as the greater of the day-ahead schedule and the unit's minimum run time. Intervals in excess of the minimum run time are treated as new segments. Combustion turbines (CTs) received $8.3 million or 71.1 percent of all balancing generator credits in the first three months of 2023. The majority of these credits, 98.6 percent, were paid to CTs committed in real time either with or without a day-ahead schedule.[19]

Uplift is higher than necessary because settlement rules do not include all revenues and costs for the entire day. Uplift is also higher than necessary because settlement rules do not disqualify units from receiving uplift when they do not follow PJM's dispatch instructions. PJM apparently considers units that start when requested and turn off when requested to be operating as requested by PJM regardless of how well the units follow the dispatch signal.[20] Units should be disqualified from receiving uplift when the units do not follow dispatch instructions, block load or self schedule.

PJM's position on the payment of uplift is illogical and PJM's definition of units not operating as requested is illogical. The logical definition of operating as requested includes both start and shutdown when requested and that units follow their dispatch signal. Both should be required in order to receive uplift. Paying uplift to units not following dispatch does not provide an incentive for flexibility. The MMU recommends that PJM develop and implement an accurate metric to define when a unit is following dispatch, instead of relying on PJM dispatchers' manual determinations, to evaluate eligibility for receiving balancing generator credits and for assessing generator deviations. As part of the metric, the MMU recommends that PJM designate units whose offers are flagged for fixed generation in Markets Gateway as not eligible for uplift. Units that are flagged for fixed generation are not dispatchable. Following dispatch is an eligibility requirement for uplift compensation.

Balancing generator credits decreased by 37.6 percent in the first three months of 2023 compared to the same time period in 2022, despite PJM's increased commitment and dispatch of CTs. Balancing generator credits paid to units in the DOM Zone decreased by 57.6 percent.

Table 4-8 shows monthly day-ahead and real-time generation by combustion turbines. In the first three months of 2023, generation by combustion turbines was 49.6 percent lower in the real-time energy market than in the day-ahead energy market. Table 4-8 shows that only 1.0 percent of generation from combustion turbines in the day-ahead market was uneconomic, while 27.5 percent of generation from combustion turbines in the real-time market was uneconomic and was paid $8.3 million in balancing generator credits. The decreased level of uneconomic real-time generation resulted in reduced balancing generator credits during the first three months of 2023.

19 Operating without of a day-ahead schedule refers to units that operate for a period either before or after their day-ahead schedule, or are committed in the real-time market and do not have a day-ahead schedule for any part of the day.

20 *See* "Operating Reserve Make Whole Credit Education," slide 13, PJM presentation to the Resource Adequacy Senior Task Force. (April 13, 2022) <https://pjm.com/-/media/committees-groups/committees/mic/2022/20220413/item-11a---operating-reserve-make-whole-credits-education.ashx>.

Table 4-8 Characteristics of day-ahead and real-time generation by combustion turbines eligible for operating reserve credits: January through March, 2023

Month	Day-Ahead Generation (GWh)	Percent of Day-Ahead Generation that was Noneconomic	Day-Ahead Generator Credits (Millions)	Real-Time Generation (GWh)	Percent of Real-Time Generation that was Noneconomic	Balancing Generator Credits (Millions)	Ratio of Day-Ahead to Real-Time Generation
Jan	1,803	0.9%	$0.0	1,275	21.8%	$3.2	1.4
Feb	1,812	1.5%	$0.0	931	31.6%	$1.4	1.9
Mar	1,602	0.6%	$0.0	1,281	30.1%	$3.7	1.2
Total (Jan - Mar)	5,216	1.0%	$0.0	3,487	27.5%	$8.3	1.5

In the first three months of 2023, balancing operating reserve credits paid to combustion turbines were $8.3 million. Of that amount, $8.2 million, or 70.0 percent of the $11.7 million in total balancing generator credits, was paid to combustion turbines operating without or outside a day-ahead schedule (Table 4-9).

Table 4-9 shows real-time generation by combustion turbines by day-ahead commitment status in the first three months of 2023 and 2022. In the first three months of 2023, 88.1 percent of real-time CT generation was from CTs that operated on a day-ahead schedule.

In the first three months of 2023, real-time CT generation operating consistent with their day-ahead schedule decreased compared to the same time period in 2022. CTs that operate on a day-ahead schedule tend to receive lower balancing generator credits because it is more likely that the day-ahead LMPs will support (prices above offer) committing the units. Day-ahead LMPs support committing the units because the day-ahead model optimizes the system for all 24 hours, unlike in real time when PJM uses ITSCED to optimize CT commitments with an approximately two hour look ahead. In addition, uplift rules continue to define all day-ahead scheduled hours as one segment for the uplift calculation (in which profits and losses during all hours offset each other). The shorter segments in real-time are defined by the minimum run time and allow for fewer offsets, amounting to greater amounts of uplift. Losses during the minimum run time segment are not offset by profits made in other segments on that day.

There are multiple reasons why the commitment of CTs is different in the day-ahead and real-time markets, including differences in the hourly pattern of load, and differences in interchange transactions. Modeling differences between the day-ahead and real-time markets also affect CT commitment, including: the modeling of different transmission constraints in the day-ahead and real-time market models; the exclusion of soak time for generators in the day-ahead market model; and the different optimization time periods used in the day-ahead and real-time markets.

Table 4-9 Real-time generation by combustion turbines by day-ahead commitment: January 2022 through March 2023

		Real-Time CT Generation Operating on a Day-Ahead Schedule				Real-Time CT Generation Operating Outside of a Day-Ahead Schedule			
Month-Year		Generation (GWh)	Share of Real-Time Generation	Percent of Real-Time Generation that is Noneconomic	Balancing Generator Credits (Millions)	Generation (GWh)	Share of Real Time Generation	Percent of Real-Time Generation that is Noneconomic	Balancing Generator Credits (Millions)
2022	Jan	840	79.5%	15.4%	$0.1	217	20.5%	54.6%	$9.1
	Feb	297	82.3%	12.7%	$0.1	64	17.7%	51.8%	$2.2
	Mar	126	41.1%	33.8%	$0.1	180	58.9%	65.2%	$4.9
	Apr	281	38.1%	25.7%	$0.1	457	61.9%	48.3%	$10.9
	May	551	53.4%	26.0%	$0.0	480	46.6%	35.2%	$8.8
	Jun	1,139	67.6%	18.8%	$0.4	545	32.4%	29.5%	$10.7
	Jul	1,694	68.7%	20.7%	$0.1	772	31.3%	33.2%	$17.9
	Aug	1,506	63.2%	20.2%	$0.1	876	36.8%	37.3%	$23.2
	Sep	880	68.3%	25.0%	$0.0	408	31.7%	38.3%	$9.3
	Oct	589	68.9%	35.0%	$0.2	266	31.1%	55.2%	$7.5
	Nov	809	73.5%	30.5%	$0.0	293	26.5%	59.5%	$9.8
	Dec	841	63.1%	22.1%	$2.0	491	36.9%	39.8%	$19.8
	Total 2022 (Jan - Mar)	1,263	73.3%	16.6%	$0.2	461	26.7%	58.4%	$16.2
2023	Jan	1,103	86.6%	17.6%	$0.0	171	13.4%	48.6%	$3.2
	Feb	845	90.8%	29.7%	$0.0	85	9.2%	50.4%	$1.4
	Mar	1,122	87.6%	25.6%	$0.1	159	12.4%	61.5%	$3.6
	Total (Jan - Mar)	3,071	88.1%	23.9%	$0.1	416	11.9%	53.9%	$8.2

Lost Opportunity Cost Credits

Balancing operating reserve lost opportunity cost (LOC) credits are intended to provide an incentive for units to follow PJM's dispatch instructions when PJM's dispatch instructions deviate from a unit's desired or scheduled output. LOC credits are paid under two scenarios.[21] The first scenario occurs if a unit of any type generating in real time with an offer price lower than the real-time LMP at the unit's bus is manually reduced or suspended by PJM due to a transmission constraint or other reliability issue. In this scenario the unit will receive a credit for LOC based on its desired output. Such units are not actually forgoing an option to increase output because the reliability of the system and in some cases the generator depend on reducing output. This LOC is referred to as real-time LOC. The second scenario occurs if a combustion turbine or diesel engine clears the day-ahead energy market, but is not committed in real time. In this scenario the unit will receive a credit which covers any lost profit in the day-ahead financial position of the unit plus the balancing energy market position. This LOC is referred to as day-ahead LOC.

Table 4-10 shows monthly day-ahead and real-time LOC credits during the first three months of 2022 and 2023. In the first three months of 2023, LOC credits decreased by $2.5 million or 41.2 percent compared to the same time period in 2022, comprised of a $2.0 million decrease in day-ahead LOC and a $0.4 million decrease in real-time LOC.

In the first three months of 2023, wind units received $0.4 million of real-time LOC, up by $0.4 million compared to the same time period in 2022. Wind units are not required to procure CIRs equal to the maximum facility output, but are paid uplift when PJM requests that the units reduce output below the maximum

21 Desired output is defined as the MW on the generator's offer curve consistent with the LMP at the generator's bus.

facility output but above the CIR level. Units do not have a right to inject power at levels greater than the CIR level that they pay for and therefore should not be paid uplift when system conditions do not permit output at a level greater than the CIR. The real-time lost opportunity costs credits paid to wind units should be based on the lowest of the desired output, the estimated output based on actual wind conditions, or the capacity interconnection rights (CIRs).

Table 4-10 Monthly lost opportunity cost credits (Millions): January 2022 through March 2023

	2022			2023		
	Day-Ahead Lost Opportunity Cost	Real-Time Lost Opportunity Cost	Total	Day-Ahead Lost Opportunity Cost	Real-Time Lost Opportunity Cost	Total
Jan	$3.3	$0.4	$3.7	$1.9	$0.0	$1.9
Feb	$1.4	$0.4	$1.8	$0.6	$0.3	$0.9
Mar	$0.5	$0.0	$0.5	$0.7	$0.0	$0.7
Apr	$0.7	$0.6	$1.3			
May	$0.9	$0.1	$1.0			
Jun	$5.1	$0.5	$5.6			
Jul	$4.6	$0.1	$4.7			
Aug	$2.5	$2.5	$5.0			
Sep	$1.5	$0.1	$1.7			
Oct	$2.6	$0.1	$2.7			
Nov	$1.0	$0.0	$1.0			
Dec	$7.8	$1.8	$9.5			
Total (Jan - Mar)	$5.2	$0.8	$6.0	$3.2	$0.3	$3.5
Share (Jan - Mar)	87.1%	12.9%	100.0%	90.2%	9.8%	100.0%
Total	$32.0	$6.5	$38.6	$3.2	$0.3	$3.5
Share	83.0%	17.0%	100.0%	90.2%	9.8%	100.0%

Table 4-11 shows day-ahead generation for combustion turbines and diesels, including scheduled day-ahead generation, scheduled day-ahead generation not requested in real time, and day-ahead generation receiving LOC credits. In the first three months of 2023, 16.1 percent of day-ahead generation by combustion turbines and diesels was not requested in real time, 2.3 percentage points higher than during the first three months of 2022. In the first three months of 2023, day-ahead generation by combustion turbines increased by 517.9 percent, day-ahead generation not requested in real time increased by 621.5 percent, and day-ahead generation not requested in real time receiving lost opportunity costs increased by 563.3 percent, compared to the same time period in 2022. Unlike steam units, combustion turbines that clear the day-ahead energy market have to be instructed by PJM to come online in real time.

Table 4-11 Day-ahead generation from combustion turbines and diesels (GWh): January 2022 through March 2023

	2022			2023		
	Day-Ahead Generation (GWh)	Day-Ahead Generation Not Requested in Real Time (GWh)	Day-Ahead Generation Not Requested in Real Time Receiving LOC Credits (GWh)	Day-Ahead Generation (GWh)	Day-Ahead Generation Not Requested in Real Time (GWh)	Day-Ahead Generation Not Requested in Real Time Receiving LOC Credits (GWh)
Jan	2,262	306	101	7,467	1,428	527
Feb	753	110	38	7,278	1,351	290
Mar	448	60	13	6,655	658	194
Apr	675	54	18			
May	1,069	101	20			
Jun	1,882	137	44			
Jul	2,603	154	57			
Aug	2,173	88	43			
Sep	1,388	96	32			
Oct	1,175	178	60			
Nov	1,279	104	31			
Dec	1,826	266	63			
Total (Jan - Mar)	3,464	476	152	21,400	3,437	1,011
Share (Jan - Mar)	100.0%	13.8%	4.4%	100.0%	16.1%	4.7%

Energy Uplift Charges

Energy Uplift Charges

Total energy uplift charges decreased by $8.6 million, or 30.5 percent, in the first three months of 2023 compared to the same time period in 2022, from $28.2 million to $19.6 million.

Table 4-12 shows total energy uplift charges by category during the first three months of 2022 and 2023.[22] The decrease of $8.6 million is comprised of a $2.3 million increase in day-ahead operating reserve charges, a $10.7 million decrease in balancing generator charges, a $0.2 million decrease in reactive service charges, and less than $0.1 million decrease in black start services charges.

Table 4-12 Total energy uplift charges by category: January through March, 2023[23]

Category	(Jan - Mar) 2022 Charges (Millions)	(Jan - Mar) 2023 Charges (Millions)	Change (Millions)	Percent Change
Day-Ahead Operating Reserves	$1.7	$4.0	$2.3	136.4%
Balancing Operating Reserves	$26.1	$15.4	($10.7)	(40.9%)
Reactive Services	$0.2	$0.0	($0.2)	(100.0%)
Synchronous Condensing	$0.0	$0.0	$0.0	0.0%
Black Start Services	$0.1	$0.1	($0.0)	(13.0%)
Total	$28.2	$19.6	($8.6)	(30.5%)
Energy Uplift as a Percent of Total PJM Billing	0.2%	0.2%	0.0%	4.6%

22 Billing data can be modified by PJM Settlements at any time to reflect changes in the evaluation of energy uplift. The billing data reflected in this report were current on April 17, 2023.
23 MMU uses Total PJM Billing values provided by PJM. For 2019 and after, the Total PJM Billing calculation was modified to better reflect PJM total billing through the PJM settlement process.

Table 4-13 compares monthly energy uplift charges by category for 2022 and the first three months of 2023.

Table 4-13 Monthly energy uplift charges: January 2022 through March 2023

	2022 Charges (Millions)						2023 Charges (Millions)					
	Day-Ahead	Balancing	Reactive Services	Synchronous Condensing	Black Start Services	Total	Day-Ahead	Balancing	Reactive Services	Synchronous Condensing	Black Start Services	Total
Jan	$0.7	$14.1	$0.0	$0.0	$0.0	$14.8	$1.7	$6.0	$0.0	$0.0	$0.0	$7.7
Feb	$0.5	$5.0	$0.0	$0.0	$0.1	$5.6	$1.0	$4.5	$0.0	$0.0	$0.0	$5.6
Mar	$0.5	$7.0	$0.2	$0.0	$0.0	$7.8	$1.3	$5.0	$0.0	$0.0	$0.1	$6.3
Apr	$0.6	$13.4	$0.0	$0.0	$0.1	$14.1						
May	$2.3	$11.9	$0.8	$0.0	$0.1	$15.1						
Jun	$4.1	$19.7	$0.0	$0.0	$0.0	$23.9						
Jul	$11.0	$25.6	$0.0	$0.0	$0.0	$36.6						
Aug	$8.3	$32.1	$0.2	$0.0	$0.0	$40.6						
Sep	$7.2	$13.4	$0.0	$0.0	$0.0	$20.6						
Oct	$0.3	$12.8	$0.1	$0.0	$0.1	$13.3						
Nov	$1.2	$13.2	$0.0	$0.0	$0.1	$14.5						
Dec	$22.0	$59.4	$0.2	$0.0	$0.0	$81.6						
Total (Jan - Mar)	$1.7	$26.1	$0.2	$0.0	$0.1	$28.2	$4.0	$15.4	$0.0	$0.0	$0.1	$19.6
Share (Jan - Mar)	6.1%	92.7%	0.8%	0.0%	0.4%	100.0%	20.6%	78.8%	0.0%	0.0%	0.6%	100.0%
Total	$58.8	$227.6	$1.5	$0.0	$0.5	$288.4	$4.0	$15.4	$0.0	$0.0	$0.1	$19.6
Share	20.4%	78.9%	0.5%	0.0%	0.2%	100.0%	20.6%	78.8%	0.0%	0.0%	0.6%	100.0%

Table 4-14 shows the composition of day-ahead operating reserve charges. Day-ahead operating reserve charges include payments for credits to generators and import transactions, day-ahead operating reserve charges for economic load response resources and day-ahead operating reserve charges from unallocated congestion charges.[24] [25] Day-ahead operating reserve charges increased by $2.3 million or 136.4 percent in the first three months of 2023 compared to the same time period in 2022.

Table 4-14 Day-ahead operating reserve charges: January through March, 2022 and 2023

Type	(Jan - Mar) 2022 Charges (Millions)	(Jan - Mar) 2023 Charges (Millions)	Change (Millions)	(Jan - Mar) 2022 Share	(Jan - Mar) 2023 Share
Day-Ahead Operating Reserve Charges	$1.7	$4.0	$2.3	100.0%	100.0%
Day-Ahead Operating Reserve Charges for Load Response	$0.0	$0.0	$0.0	0.0%	0.0%
Unallocated Congestion Charges	$0.0	$0.0	$0.0	0.0%	0.0%
Total	$1.7	$4.0	$2.3	100.0%	100.0%

Table 4-15 shows the composition of the balancing operating reserve charges. Balancing operating reserve charges consist of balancing operating reserve reliability charges (credits to generators), balancing operating reserve deviation charges (credits to generators and import transactions), balancing operating reserve charges for economic load response and balancing local constraint charges. Balancing operating reserve charges decreased by $10.7 million or 40.9 percent in the first three months of 2023 compared to the same time period in 2022.

24 See PJM Operating Agreement Schedule 1 § 3.2.3(c). Unallocated congestion charges are added to the total costs of day-ahead operating reserves. Congestion charges have been allocated to day-ahead operating reserves only 10 times since 1999, totaling $26.9 million.
25 See the *2022 State of the Market Report for PJM*, Section 13, Financial Transmission Rights and Auction Revenue Rights.

Table 4-15 Balancing operating reserve charges: January through March, 2022 and 2023

Type	(Jan - Mar) 2022 Charges (Millions)	(Jan - Mar) 2023 Charges (Millions)	Change (Millions)	(Jan - Mar) 2022 Share	(Jan - Mar) 2023 Share
Balancing Operating Reserve Reliability Charges	$11.6	$7.8	($3.8)	44.5%	50.8%
Balancing Operating Reserve Deviation Charges	$13.4	$7.5	($5.9)	51.3%	48.5%
Balancing Operating Reserve Charges for Load Response	$0.0	$0.0	($0.0)	0.0%	0.0%
Balancing Local Constraint Charges	$1.1	$0.1	($1.0)	4.2%	0.8%
Total	$26.1	$15.4	($10.7)	100.0%	100.0%

Table 4-16 shows the composition of the balancing operating reserve deviation charges. Balancing operating reserve deviation charges are the sum of: make whole credits paid to generators and import transactions, energy lost opportunity costs paid to generators, and payments to resources scheduled by PJM but canceled by PJM before coming online. In the first three months of 2023, energy lost opportunity cost deviation charges decreased by $2.5 million or 41.2 percent, and make whole deviation charges decreased by $3.5 million or 46.5 percent compared to the same time period in 2022.

Table 4-16 Balancing operating reserve deviation charges: January through March, 2022 and 2023

Charge Attributable To	(Jan - Mar) 2022 Charges (Millions)	(Jan - Mar) 2023 Charges (Millions)	Change (Millions)	(Jan - Mar) 2022 Share	(Jan - Mar) 2023 Share
Make Whole Payments to Generators and Imports	$7.4	$4.0	($3.5)	55.5%	53.2%
Energy Lost Opportunity Cost	$6.0	$3.5	($2.5)	44.5%	46.8%
Canceled Resources	$0.0	$0.0	$0.0	0.0%	0.0%
Total	$13.4	$7.5	($5.9)	100.0%	100.0%

Table 4-17 shows reactive services, synchronous condensing and black start services charges. Reactive services charges decreased by $0.2 million or 100.0 percent in the first three months of 2023, compared to the same time period in 2022.

Table 4-17 Additional energy uplift charges: January through March, 2022 and 2023

Type	(Jan - Mar) 2022 Charges (Millions)	(Jan - Mar) 2023 Charges (Millions)	Change (Millions)	(Jan - Mar) 2022 Share	(Jan - Mar) 2023 Share
Reactive Services Charges	$0.2	$0.0	($0.2)	64.9%	0.0%
Synchronous Condensing Charges	$0.0	$0.0	$0.0	0.0%	0.0%
Black Start Services Charges	$0.1	$0.1	($0.0)	35.1%	100.0%
Total	$0.4	$0.1	($0.2)	100.0%	100.0%

Operating Reserve Rates

Under the operating reserves cost allocation rules, PJM calculates ten separate rates: a day-ahead operating reserve rate, a reliability rate for each region (RTO, East, or West), a deviation rate for each region, a lost opportunity cost rate, a canceled resources rate, and a dispatch differential lost opportunity cost rate.

Table 4-18 illustrates the composition of charges and the transactions included in the charge calculation. For example, balancing operating reserve charges for deviations are calculated by adding the RTO deviation rate, the regional deviation rates, the LOC rate, and the canceled resources rate. For example, the INCs are responsible for paying the RTO deviation rate, the regional deviation rate, the LOC rate, and the canceled resources rate.[26]

Table 4-18 Composition of charges

		Transaction / Resource Type								
Charge	Rate	Load	Generation	Imports[1]	Exports[1]	Wheels	Economic DR	INCs	DECs	UTCs
Day-Ahead Operating Reserve	Day-Ahead Operating Reserve Rate	X			X				X	X
Balancing Operating Reserves for Reliability	RTO Reliability Rate	X			X					
	Regional (East or West) Reliability Rate	X			X					
Balancing Operating Reserves for Deviations[2]	RTO Deviation Rate	X	X	X	X		X	X	X	X
	Regional (East or West) Deviation Rate	X	X	X	X		X	X	X	X
	LOC Rate	X	X	X	X		X	X	X	
	Canceled Resources Rate	X	X	X	X		X	X	X	
Reactive Services	Implicit Rates	X								
Black Start Services	Implicit Rates	X[3]		X[4]	X[4]	X[4]				
Synchronous Condensing	Implicit Rate	X			X					

[1] Dynamic scheduled transactions are exempt from operating reserve charges.
[2] Participants only pay deviation charges if they incur deviations based on the rules specified in Manual 28.
[3] Load is charged black start services based on their zonal peak load contribution.
[4] Interchange transactions are charged black start services based on their point to point firm and non-firm reservations.

Table 4-19 shows the average rates for each region in each charge category for the first three months of 2022 and 2023. The average day-ahead rate in the first three months of 2023 was 0.016 $/MWh, with a minimum rate of 0.00 $/MWh and a maximum rate of 0.148 $/MWh. The average rate for the first three months of 2023 is 0.009 $/MWh higher than the average day-ahead rate in the first three months of 2022.

The average RTO reliability rate in the first three months of 2023 was 0.029 $/MWh, with a minimum rate of 0.01 $/MWh and a maximum rate of 0.228 $/MWh. The average RTO reliability rate in the first three months of 2023 is 0.020 $/MWh lower than the average rate in the first three months of 2022.

The average RTO deviation rate in the first three months of 2023 was 0.028 $/MWh, with a minimum rate of 0.00 $/MWh and a maximum rate of 0.216 $/MWh. The average RTO deviation rate in the first three months of 2023 is 0.063 $/MWh lower than the average rate in the first three months of 2022.

26 The lost opportunity cost and canceled resources rates are not posted separately by PJM. PJM adds the lost opportunity cost and the canceled resources rates to the deviation rate for the RTO Region since these three charges are allocated following the same rules.

Table 4-19 Operating reserve rates ($/MWh): January through March, 2022 and 2023

Rate	Avg 2022 (Jan - Mar) ($/MWh)	Min 2022 (Jan - Mar) ($/MWh)	Max 2022 (Jan - Mar) ($/MWh)	Avg 2023 (Jan - Mar) ($/MWh)	Min 2023 (Jan - Mar) ($/MWh)	Max 2023 (Jan - Mar) ($/MWh)	Difference of Avg ($/MWh)	Percent Difference of Avg
Day-Ahead	0.007	(0.000)	0.155	0.016	(0.000)	0.148	0.009	119.5%
Day-Ahead with Unallocated Congestion	0.007	(0.000)	0.155	0.016	(0.000)	0.148	0.009	119.5%
RTO Reliability	0.050	0.001	0.450	0.029	0.001	0.228	(0.020)	(41.2%)
East Reliability	0.011	0.000	0.237	0.019	0.000	0.330	0.008	73.3%
West Reliability	0.000	0.000	0.034	0.002	0.000	0.106	0.001	310.4%
RTO Deviation	0.090	(0.000)	0.823	0.028	(0.000)	0.216	(0.063)	(69.2%)
East Deviation	0.031	0.000	0.756	0.025	0.000	0.677	(0.006)	(20.5%)
West Deviation	0.004	0.000	0.115	0.003	0.000	0.074	(0.000)	(8.6%)
Lost Opportunity Cost	0.085	0.000	0.895	0.037	0.000	0.814	(0.049)	(57.0%)
Canceled Resources	0.000	0.000	0.000	0.000	0.000	0.000	NA	N/A
Dispatch Differential Lost Opportunity Cost	0.002	0.000	0.021	0.001	0.000	0.005	NA	N/A

Reactive Services Rates

Reactive services charges associated with local voltage support are allocated to real-time load in the control zone or zones where the service is provided. These charges result from uplift payments to units committed by PJM to support reactive/voltage requirements that do not recover their energy offer through LMP payments if they are committed out of merit to provide reactive, or incur opportunity costs associated with reduced energy output. These charges are separate from the reactive service capability revenue requirement charges which are a fixed annual charge based on approved FERC filings.[27] Reactive services charges associated with supporting reactive transfer interfaces above 345 kV are allocated daily to real-time load across the entire RTO based on the real-time load ratio share of each network customer.

While reactive services rates are not posted by PJM, a local voltage support rate for each control zone can be calculated and a reactive transfer interface support rate can be calculated for the entire RTO. Table 4-20 shows the reactive services rates associated with local voltage support in the first three months of 2022 and 2023. Table 4-20 shows that in the first three months of 2023 no zones incurred reactive services charges.

27 See *2021 State of the Market Report for PJM*, Volume 2; Section 10: Ancillary Service Markets.

Table 4-20 Local voltage support rates: January through March, 2022 and 2023

Control Zone	(Jan - Mar) 2022 ($/MWh)	(Jan - Mar) 2023 ($/MWh)	Difference ($/MWh)	Percent Difference
ACEC	0.000	0.000	0.000	0.0%
AEP	0.000	0.000	0.000	0.0%
APS	0.000	0.000	0.000	0.0%
ATSI	0.000	0.000	0.000	0.0%
BGE	0.000	0.000	0.000	0.0%
COMED	0.000	0.000	0.000	0.0%
DAY	0.000	0.000	0.000	0.0%
DUKE	0.000	0.000	0.000	0.0%
DUQ	0.000	0.000	0.000	0.0%
DOM	0.007	0.000	(0.007)	(100.0%)
DPL	0.001	0.000	(0.001)	(100.0%)
EKPC	0.000	0.000	0.000	0.0%
JCPLC	0.000	0.000	0.000	0.0%
MEC	0.000	0.000	0.000	0.0%
OVEC	0.000	0.000	0.000	0.0%
PECO	0.000	0.000	0.000	0.0%
PE	0.000	0.000	0.000	0.0%
PEPCO	0.000	0.000	0.000	0.0%
PPL	0.000	0.000	0.000	0.0%
PSEG	0.000	0.000	0.000	0.0%
REC	0.000	0.000	0.000	0.0%

Geography of Charges and Credits

Table 4-21 shows the geography of charges and credits in the first three months of 2023. Table 4-21 includes only day-ahead operating reserve charges and balancing operating reserve reliability and deviation charges since these categories are allocated regionally, while other charges, such as reactive services, synchronous condensing and black start services are allocated by control zone, and balancing local constraint charges are charged to the requesting party.

Charges are categorized by the location (control zone, hub, aggregate or interface) where they are allocated according to PJM's operating reserve rules. Credits are categorized by the location where the resources are located. The shares columns reflect the operating reserve credits and charges balance for each location. For example, load, virtual transactions, and generators in the PPL Control Zone paid 4.9 percent of all operating reserve charges allocated regionally while resources in the PPL Control Zone were paid 1.4 percent of the corresponding credits. The PPL Control Zone received fewer operating reserve credits than operating reserve charges paid and had 12.4 percent of the deficit. The deficit is the net of the credits and charges paid at a location. Transactions in the BGE Control Zone paid 3.3 percent of all operating reserve charges allocated regionally, and resources in the BGE Control Zone were paid 23.2 percent of the corresponding credits. The BGE Control Zone received fewer operating reserve credits than operating reserve charges paid and had 64.7 percent of the surplus. The surplus is the net of the credits and charges paid at a location. Table 4-21 also shows that 89.4 percent of all charges were allocated in control zones, 3.3 percent in hubs and aggregates and 7.3 percent in interfaces.

Table 4-21 Geography of regional charges and credits: January through March, 2023

					Shares			
Location		Charges (Millions)	Credits (Millions)	Balance	Total Charges	Total Credits	Deficit	Surplus
Zones	ACEC	$0.3	$0.4	$0.1	1.4%	1.9%	0.0%	1.7%
	AEP	$2.5	$2.0	($0.5)	12.8%	10.4%	8.3%	0.0%
	APS	$0.8	$0.7	($0.1)	4.1%	3.8%	1.1%	0.0%
	ATSI	$1.0	$1.9	$0.9	5.2%	9.8%	0.0%	15.1%
	BGE	$0.6	$4.5	$3.8	3.3%	23.2%	0.0%	64.7%
	COMED	$1.7	$1.1	($0.6)	8.8%	5.8%	10.3%	0.0%
	DAY	$0.4	$0.5	$0.1	1.9%	2.6%	0.0%	2.3%
	DUKE	$0.5	$0.5	($0.0)	2.6%	2.6%	0.1%	0.0%
	DUQ	$0.2	$0.0	($0.2)	1.2%	0.0%	4.0%	0.0%
	DOM	$3.9	$4.5	$0.7	20.0%	23.4%	0.0%	11.2%
	DPL	$0.5	$0.4	($0.1)	2.3%	2.0%	1.1%	0.0%
	EKPC	$0.5	$0.3	($0.2)	2.7%	1.8%	3.3%	0.0%
	External	$0.0	$0.2	$0.2	0.0%	0.8%	0.0%	2.8%
	JCPLC	$0.4	$0.1	($0.3)	2.1%	0.4%	5.9%	0.0%
	MEC	$0.4	$0.3	($0.1)	1.8%	1.4%	1.5%	0.0%
	OVEC	$0.1	$0.0	($0.1)	0.4%	0.1%	1.2%	0.0%
	PECO	$0.7	$0.0	($0.7)	3.8%	0.1%	12.6%	0.0%
	PE	$0.4	$0.5	$0.0	2.3%	2.4%	0.0%	0.3%
	PEPCO	$0.6	$0.7	$0.1	2.9%	3.5%	0.0%	2.0%
	PPL	$1.0	$0.3	($0.7)	4.9%	1.4%	12.4%	0.0%
	PSEG	$0.8	$0.5	($0.3)	4.2%	2.5%	5.8%	0.0%
	REC	$0.1	$0.0	($0.1)	0.6%	0.0%	2.0%	0.0%
	All Zones	$17.3	$19.4	$2.1	89.4%	100.3%	69.6%	100.0%
Hubs and Aggregates	AEP - Dayton	$0.1	$0.0	($0.1)	0.7%	0.0%	2.4%	0.0%
	Dominion	$0.1	$0.0	($0.1)	0.5%	0.0%	1.7%	0.0%
	Eastern	$0.1	$0.0	($0.1)	0.3%	0.0%	1.0%	0.0%
	New Jersey	$0.0	$0.0	($0.0)	0.2%	0.0%	0.6%	0.0%
	Ohio	$0.1	$0.0	($0.1)	0.4%	0.0%	1.4%	0.0%
	Western Interface	$0.0	$0.0	$0.0	0.0%	0.0%	0.0%	0.0%
	Western	$0.2	$0.0	($0.2)	1.2%	0.0%	4.2%	0.0%
	RTEP B0328 Source	$0.0	$0.0	$0.0	0.0%	0.0%	0.0%	0.0%
	All Hubs and Aggregates	$0.6	$0.0	($0.6)	3.3%	0.0%	11.3%	0.0%
Interfaces	CPLE Exp	$0.0	$0.0	$0.0	0.0%	0.0%	0.0%	0.0%
	CPLE Imp	$0.0	$0.0	$0.0	0.0%	0.0%	0.0%	0.0%
	Duke Exp	$0.0	$0.0	$0.0	0.0%	0.0%	0.0%	0.0%
	Duke Imp	$0.0	$0.0	$0.0	0.0%	0.0%	0.0%	0.0%
	Hudson	$0.1	$0.0	($0.1)	0.6%	0.0%	2.1%	0.0%
	IMO	$0.1	$0.0	($0.1)	0.4%	0.0%	1.4%	0.0%
	Linden	$0.1	$0.0	($0.1)	0.3%	0.0%	1.2%	0.0%
	MISO	$0.4	$0.0	($0.4)	1.9%	0.0%	6.6%	0.0%
	NCMPA Imp	$0.0	$0.0	$0.0	0.0%	0.0%	0.0%	0.0%
	Neptune	$0.1	$0.0	($0.1)	0.6%	0.0%	1.9%	0.0%
	NIPSCO	$0.0	$0.0	$0.0	0.0%	0.0%	0.0%	0.0%
	Northwest	$0.0	$0.0	$0.0	0.0%	0.0%	0.0%	0.0%
	NYIS	$0.3	$0.0	($0.3)	1.7%	0.0%	5.8%	0.0%
	South Exp	$0.0	$0.0	$0.0	0.0%	0.0%	0.0%	0.0%
	South Imp	$0.0	$0.0	$0.0	0.0%	0.0%	0.0%	0.0%
	South	$0.4	$0.0	($0.4)	1.8%	0.0%	6.4%	0.0%
	All Interfaces	$1.4	$0.0	($1.4)	7.3%	0.0%	19.1%	0.0%
	Total	$19.4	$19.4	$0.0	100.0%	100.3%	100.0%	100.0%

Uplift Eligibility

In PJM, units have either a pool scheduled or self scheduled commitment status. Pool scheduled units are committed by PJM while self scheduled units are committed by generation owners. Table 4-22 provides a description of commitment and dispatch status, uplift eligibility and the ability to set price.[28] In the day-ahead energy market only pool scheduled resources are eligible for day-ahead operating reserve credits. A unit may be self scheduled in the day-ahead market and then be pool scheduled and dispatched in subsequent days to remain online, in which case they would be eligible for uplift for the subsequent days. In the real-time energy market only pool scheduled resources that follow PJM's dispatch are defined in the tariff as eligible for balancing operating reserve credits. However, in practice, units receive uplift credits when not following PJM's dispatch signal Units are paid day-ahead operating reserve credits based on their scheduled operation for the entire day. Balancing operating reserve credits are paid on a segmented basis for each period defined by the greater of the day-ahead schedule and minimum run time. Resources receive day-ahead and balancing operating reserve credits only when they are eligible and unable to recover their operating cost for the day or segment.[29]

Table 4-22 Dispatch status, commitment status and uplift eligibility[30]

		Commitment Status	
Dispatch Status	Dispatch Description	Self Scheduled (units committed by the generation owner)	Pool Scheduled and following PJM's dispatch signal (units committed by PJM)
Block Loaded	MWh offered to PJM as a single MWh block which is not dispatchable	Not eligible to receive uplift Not eligible to set LMP	Eligible to receive uplift Not eligible to set LMP unless fast start eligible
Economic Minimum	MWh from the nondispatchable economic minimum component for units that offer a dispatchable range to PJM	Not eligible to receive uplift Not eligible to set LMP	Eligible to receive uplift Not eligible to set LMP unless fast start eligible
Dispatchable	MWh above the economic minimum level for units that offer a dispatchable range to PJM.	Only eligible to receive LOC credits if dispatched down by PJM Eligible to set LMP	Eligible to receive uplift Eligible to set LMP

28 PJM has modified the basic rules of eligibility to set price using its CT price setting logic.
29 Resources do not recover their operating cost when market revenues for the day are less than the short run marginal cost defined by the startup, no load, and incremental offer curve.
30 PJM allows block loaded CTs to set LMP by relaxing the economic minimum by 10 to 20 percent using CT price setting logic.

Energy Uplift Issues

Uplift Resettlement

Some units have been incorrectly paid uplift despite not meeting uplift eligibility requirements, including not following dispatch, not having the correct commitment status, or not operating with PLS offer parameters. The MMU has requested that PJM correctly resettle the uplift payments in these cases.[31] Since 2018, the cumulative resettlement requests total $15.1 million, of which PJM has agreed and resettled 9.2 percent over the last two years, and 18.1 percent remain pending. The remaining 60.6 percent occurred prior to January 2021 and would now require a directive from FERC for them to be resettled.[32] PJM has refused to accept the voluntary return of incorrectly paid uplift credits by generators when the MMU has identified such cases. The MMU continues to bring new cases to the attention of PJM.

The MMU identifies units that are not following dispatch and that are therefore not eligible to receive uplift payments. These findings are communicated to unit owners and to PJM. The units are identified by comparing their actual generation to the dispatch level that they should have achieved based on the real-time LMP, unit operating parameters (e.g. economic minimum, maximum and ramp rate) and energy offer.

Intraday Segments Uplift Settlement

PJM pays uplift separately for multiple segmented blocks of time during the operating day (intraday).[33] The use of intraday segments to calculate the need for uplift payments results in higher uplift payments than necessary to make units whole, including uplift payments to units that are profitable on a daily basis. The MMU recommends eliminating intraday segments from the calculation of uplift payments and returning to calculating the need for uplift based on the entire 24 hour operating day.

31 To date, the MMU has only requested resettlement of the most egregious cases.
32 OATT § 10.4.
33 See PJM "Manual 28: Operating Reserve Accounting," Rev. 89 (Nov. 1, 2022).

Table 4-23 shows balancing operating reserve credits calculated using intraday segments and balancing operating reserve payments calculated on a daily basis. In the first three months of 2023, balancing operating reserve credits would have been $1.9 million or 16.7 percent lower if they were calculated on a daily basis. In the first three months of 2022, balancing operating reserve credits would have been $3.3 million or 17.7 percent lower if they were calculated on a daily basis.

Table 4-23 Intraday segments and daily balancing operating reserve credits: January 2022 through March 2023

	2022 Balancing Generator Credits (Millions)			2023 Balancing Generator Credits (Millions)		
	Intraday Segments Calculation	Daily Calculation	Difference	Intraday Segments Calculation	Daily Calculation	Difference
Jan	$10.2	$8.5	($1.8)	$4.0	$3.2	($0.8)
Feb	$3.2	$2.5	($0.7)	$3.5	$3.0	($0.4)
Mar	$5.3	$4.5	($0.8)	$4.2	$3.5	($0.8)
Apr	$11.9	$9.9	($1.9)			
May	$10.6	$7.9	($2.7)			
Jun	$13.8	$9.7	($4.1)			
Jul	$20.3	$14.5	($5.8)			
Aug	$26.6	$18.7	($8.0)			
Sep	$11.5	$6.1	($5.4)			
Oct	$8.7	$6.6	($2.2)			
Nov	$11.9	$9.8	($2.1)			
Dec	$48.7	$42.2	($6.5)			
Total (Jan - Mar)	$18.7	$15.4	($3.3)	$11.7	$9.7	($1.9)

Prior to April 1, 2018, for purposes of calculating LOC credits, each hour was defined as a unique segment. Following the implementation of five minute settlements on April 1, 2018, LOC credits are calculated with each five minute interval defined as a unique segment. Thus a profit in one five minute segment, resulting from the real-time LMP being lower than the day-ahead LMP, is not used to offset a loss in any other five minute segment. This change in settlements causes an increase in LOC credits compared to hourly settlement as generators are made whole for any losses incurred in a five minute interval while previously gains and losses were netted within the hour. Table 4-24 shows the impact on day-ahead LOC credits to CTs that are committed DA but not RT. The table shows the LOC credits calculated in three ways: with the five minute settlement calculations implemented in April 2018; with hourly settlements prior to the change in April 2018; and with daily settlements. In the first three months of 2023, LOC credits would have been $1.1 million or 11.4 percent lower if they had been settled on an hourly basis rather than on a five minute basis. In the first three months of 2023, LOC credits would have been $2.7 million or 28.8 percent lower if they had been settled on the recommended daily basis rather than being settled on a five minute basis.

Table 4-24 Comparison of five minute, hourly, and daily settlement of day-ahead lost opportunity cost credits: January through March, 2023

	2023 Day-Ahead LOC Credits (Millions)				
	Five Minute Settlement (Status Quo)	Hourly Settlement (Pre-April 2018)	Difference	Daily Settlement (Recommendation)	Difference
Jan	$5.7	$5.1	($0.6)	$4.4	($1.3)
Feb	$1.8	$1.5	($0.3)	$1.0	($0.8)
Mar	$2.0	$1.8	($0.2)	$1.4	($0.6)
Total (Jan - Mar)	$9.5	$8.4	($1.1)	$6.7	($2.7)

Concentration of Energy Uplift Credits

The recipients of uplift payments are highly concentrated by unit and by company. This concentration results from a combination of unit operating parameters, PJM's persistent need to commit specific units out of merit in particular locations and the fact that a lack of full transparency has made it more difficult for competition to affect these payments.[34]

Table 4-25 shows the concentration of energy uplift credits. The top 10 units received 37.3 percent of total energy uplift credits in the first three months of 2023, compared to 16.5 percent in the same time period in 2022. The top 10 companies received 42.3 percent of total energy uplift credits in the first three months of 2023, compared to 20.8 percent in the same time period in 2021.

34 As a result of FERC Order No. 844, PJM began publishing total uplift credits by unit by month for credits paid on and after July 1, 2019, on September 10, 2019.

Table 4-25 Top 10 units and organizations energy uplift credits: January through March, 2023

		Top 10 Units		Top 10 Organizations	
Category	Type	Credits (Millions)	Credits Share	Credits (Millions)	Credits Share
Day-Ahead	Generators	$4.0	98.8%	$4.0	99.6%
Balancing	Canceled Resources	$0.0	NA	$0.0	NA
	Generators	$3.2	27.3%	$8.7	74.2%
	Local Constraints Control	$0.1	100.0%	$0.1	100.0%
	Lost Opportunity Cost	$1.9	52.9%	$2.9	82.9%
	Dispatch Differential Lost Opportunity Cost	$0.0	29.2%	$0.1	73.6%
	Total Balancing	$5.2	33.7%	$11.8	76.3%
Reactive Services		$0.0	NA	$0.0	NA
Synchronous Condensing		$0.0	NA	$0.0	NA
Black Start Services		$0.1	80.7%	$0.1	100.0%
Total		$7.3	20.8%	$14.8	42.3%

Unit Specific Uplift Payments

FERC Order No. 844 allows PJM and the MMU to publish unit specific uplift payments by category by month. Table 4-26 through Table 4-30 show the top 10 recipients of total uplift, day-ahead operating reserve credits and lost opportunity cost credits.

Table 4-26 Top 10 recipients of total uplift: January through March, 2023

Rank	Unit Name	Zone	Total Uplift Credit	Share of Total Uplift Credits
1	BC BRANDON SHORES 2 F	BGE	$3,793,095	19.4%
2	PEP CHALKPOINT 3 F	PEPCO	$600,893	3.1%
3	BC WAGNER 4 F	BGE	$463,480	2.4%
4	VP BRUNSWICK 1 LF	DOM	$412,368	2.1%
5	VP DOSWELL 2 CT	DOM	$367,089	1.9%
6	FE LEMOYNE 3 CT	ATSI	$353,141	1.8%
7	FE LEMOYNE 4 CT	ATSI	$346,112	1.8%
8	FE LEMOYNE 1 CT	ATSI	$330,749	1.7%
9	VP CHARLES CITY 1 CT	DOM	$317,375	1.6%
10	VP DOSWELL 3 CT	DOM	$315,343	1.6%
Total of Top 10			$7,299,644	37.3%
Total Uplift Credits			$19,583,094	100.0%

Table 4-27 Top 10 recipients of day-ahead generation credits: January through March, 2023

Rank	Unit Name	Zone	Day-Ahead Operating Reserve Credit	Share of Day-Ahead Operating Reserve Credits
1	BC BRANDON SHORES 2 F	BGE	$3,241,356	80.3%
2	PEP CHALKPOINT 3 F	PEPCO	$596,445	14.8%
3	DPL WILDCAT POINT 1 CC	DPL	$53,360	1.3%
4	PL NORTHAMPTON 1 F	PPL	$32,962	0.8%
5	PL BRUNNER ISLAND 2 F	PPL	$20,953	0.5%
6	JC REDOAK 1 CC	JCPLC	$13,286	0.3%
7	AEP MITCHELL - KAMMER 2 F	AEP	$12,843	0.3%
8	PS LINDEN 1CC	PSEG	$8,483	0.2%
9	PS BERGEN 1CC F	PSEG	$5,761	0.1%
10	PS NEWARK ENERGY CENTER 10 CC	PSEG	$5,196	0.1%
Total of Top 10			$3,990,646	98.8%
Total day-ahead operating reserve credits			$4,037,214	100.0%

Table 4-28 Top 10 recipients of balancing generator credits: January through March, 2023

Rank	Unit Name	Zone	Balancing Generator Credits	Share of Balancing Generator Credits
1	BC BRANDON SHORES 2 F	BGE	$551,739	4.7%
2	BC WAGNER 4 F	BGE	$463,480	4.0%
3	VP BRUNSWICK 1 LF	DOM	$412,368	3.5%
4	VP CHARLES CITY 1 CT	DOM	$317,375	2.7%
5	VP CHESTERFIELD 1 LF	DOM	$300,687	2.6%
6	VP DOSWELL 2 CT	DOM	$256,065	2.2%
7	VP DOSWELL 3 CT	DOM	$240,639	2.1%
8	VP FOUR RIVERS 1 CT	DOM	$240,433	2.1%
9	VP MARSHRUN 3 CT	DOM	$205,085	1.8%
10	VP MARSHRUN 1 CT	DOM	$202,377	1.7%
Total of Top 10			$3,190,247	27.3%
Total balancing operating reserve credits			$11,675,107	100.0%

Table 4-29 Top 10 recipients of lost opportunity cost credits: January through March, 2023

Rank	Unit Name	Zone	Lost Opportunity Cost Credits	Share of Lost Opportunity Cost Credits
1	FE LEMOYNE 3 CT	ATSI	$328,213	9.4%
2	FE LEMOYNE 4 CT	ATSI	$320,417	9.1%
3	FE LEMOYNE 1 CT	ATSI	$311,384	8.9%
4	FE LEMOYNE 2 CT	ATSI	$279,633	8.0%
5	VP REMINGTON 1 CT	DOM	$134,888	3.9%
6	VP DOSWELL 2 CT	DOM	$110,013	3.1%
7	AP CHAMBERSBURG 4-7 D	AP	$104,868	3.0%
8	AEP GARDEN CREEK - BUCHANAN CT 1-2	AEP	$96,444	2.8%
9	VP LADYSMYTH 2 CT	DOM	$93,808	2.7%
10	ACE SHERMAN 1 CT	ACEC	$74,474	2.1%
Total of Top 10			$1,854,144	52.9%
Total lost opportunity cost credits			$3,502,228	100.0%

Table 4-30 Top 10 recipients of dispatch differential lost opportunity cost credits: January through March, 2023

Rank	Unit Name	Zone	Dispatch Differential Lost Opportunity Cost Credits	Share of Dispatch Differential Lost Opportunity Cost Credits
1	AEP GAVIN 1 F	AEP	$6,926	5.0%
2	OVEC CLIFTY CREEK 6 F	OVEC	$5,445	3.9%
3	PL HUMMEL STATION 1 CC	PPL	$5,076	3.6%
4	AEP GAVIN 2 F	AEP	$4,198	3.0%
5	AEP COVERT 2 CC	AEP	$3,387	2.4%
6	PN HOMER CITY 1 F	PE	$3,344	2.4%
7	FE FREMONT ENERGY CENTER 3 CC	ATSI	$3,338	2.4%
8	COM 935 KENDALL 3 CC	COMED	$3,134	2.2%
9	COM 21 KINCAID 1 F	COMED	$2,992	2.1%
10	COM 21 KINCAID 2 F	COMED	$2,893	2.1%
Total of Top 10			$40,734	29.2%
Total dispatch differential lost opportunity cost credits			$139,417	4.0%

Uplift Credits and Market Power Mitigation

Absent effectively implemented market power mitigation, unit owners that submit noncompetitive offers or offers with inflexible operating parameters, can exercise market power, resulting in noncompetitive and excessive uplift payments.

The three pivotal supplier (TPS) test is the test for local structural market power in the energy market.[35] If the TPS test is failed, market power mitigation is applied by offer capping the resources of the owners identified as having local market power. Offer capping is designed to set offers at competitive levels.

Table 4-31 shows the uplift credits paid to committed and dispatched units in the first three months of 2023 by offer type. Units received $7.5 million or 63.9 percent of balancing generator credits and $0.1 million or 3.6 percent of day-ahead operating reserve credits in the first three months of 2023 using price-based offers. Units received $3.3 million or 28.0 percent of balancing generator credits and $3.9 million or 95.9 percent of day-ahead operating reserves in the first three months of 2023 using cost-based offers.

Table 4-31 Operating Reserve Credits by Offer Type: January through March, 2023

Offer Type	Day Ahead Operating Reserve Credits (Millions)	Balancing Generator Credits (Millions)	Day Ahead Reactive Credits (Millions)	Real Time Reactive Credits (Millions)	Total	Share of Total Uplift
Cost	$3.9	$3.3	$0.0	$0.0	$7.1	36.4%
Price	$0.1	$7.5	$0.0	$0.0	$7.6	38.8%
Price PLS	$0.0	$0.7	$0.0	$0.0	$0.7	3.5%
Cost & Price	$0.0	$0.3	$0.0	$0.0	$0.3	1.4%
Cost & PLS	$0.0	$0.0	$0.0	$0.0	$0.0	0.0%
Price & PLS	$0.0	$0.0	$0.0	$0.0	$0.0	0.0%
Total	$4.0	$11.7	$0.0	$0.0	$15.7	80.2%
Share	25.7%	74.3%	0.0%	0.0%	100.0%	NA

Table 4-32 shows day-ahead operating reserve credits paid to units called on days with hot and cold weather alerts, classified by commitment schedule type. Of all the day-ahead credits received during days with weather alerts, 77.3 percent went to units that were committed on cost schedules, which are parameter limited, 10.5 percent went to units that were committed on price PLS schedules and 12.2 percent went to units committed on price schedules less flexible than PLS. The 12.2 percent that went to units committed on a price schedule less flexible than PLS indicates an issue with the process that PJM uses to apply parameter mitigation on weather alert days. Resources

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

should not receive uplift based on inflexible parameters during emergencies and alerts.

Table 4-32 Day-ahead operating reserve credits during weather alerts by commitment schedule: January through March, 2023

Commitment Type During Hot and Cold Weather Alerts	Day Ahead Operating Reserve Credits	Share of DAOR during emergency alerts
Committed on cost (cost capped)	$129,202	77.3%
Committed on price schedule as flexible as PLS	$0	0.0%
Committed on price schedule less flexible than PLS	$20,432	12.2%
Committed on price PLS	$17,556	10.5%
Total	$167,190	100.0%

Fast Start Pricing

Fast start pricing was implemented on September 1, 2021. With fast start pricing, cleared and dispatched MW are determined in the dispatch run, identical to the combined dispatch and pricing process prior to fast start, while LMPs are determined in the pricing run, which calculates prices based on the counterfactual assumption that the fast start resources are flexible and can back down to a low economic minimum MW. Fast start pricing creates a divergence between the pricing run LMP that signals a higher MW for some resources and the lower dispatch run MW to which PJM dispatches the resource based on its offer curve. The resources dispatched down would produce more MWh if they responded to the actual market LMP from the pricing run.

As a result, the implementation of fast start pricing required a new uplift credit to pay the lost opportunity costs of units that are backed down in real time to accommodate the less flexible fast start units for which fast start pricing assumes flexibility. The resulting dispatch differential lost opportunity cost credit is the revenue lost by the resource as a result of operating at the lower dispatch MW rather than the MW on its offer curve corresponding to the actual market LMP from the pricing run. Table 4-1 shows that the dispatch differential lost opportunity cost for the first three months of 2023 was $0.1 million. Table 4-5 shows that 42.0 percent of the dispatch differential lost opportunity cost credit was paid to combined cycle units and 11.4 percent to combustion turbines.

In some cases, PJM paid dispatch differential payments to resources that did not follow PJM dispatch instructions. PJM should not make these payments as they are directly counter to the logic of fast start pricing as well as to tariff rules. The MMU recommends that PJM not make such payments and require refunds where it has not already done so. This is part of the broader recommendation that PJM stop paying uplift to resources that do not follow dispatch.

A primary argument made by the proponents of fast start pricing is that it will reduce uplift to fast start units by raising LMP, and thus revenue, when they are operating. This reduction in uplift would be most likely to occur in balancing operating reserves payments. To the extent that fast start pricing increases day-ahead prices, it may also reduce Day-Ahead Operating Reserve payments. But fast start pricing also increases other uplift payments, especially the new dispatch differential lost opportunity cost payment. Day-ahead lost opportunity cost payments to fast start resources may also increase because real-time LMPs are higher than they would be without fast start pricing.

Table 4-33 shows the amount of uplift paid to fast start units by major uplift category. Fast start units received $2.9 million in balancing generator credits, or 25.0 percent of total balancing operating reserves. Fast start units received $0.5 million in day-ahead lost opportunity costs, or 1.7 percent of all lost opportunity costs. Fast start units received less than $0.1 million in day-ahead operating credits, or less than 0.1 percent of total day-ahead operating reserve credits.

Table 4-33 Monthly day-ahead operating reserves, balancing generator credits, and day-ahead lost opportunity cost credits for fast start units: January through March, 2023

Month	Day-Ahead Operating Reserves (Millions)	Share of Monthly Day-Ahead Operating Reserves	Balancing Generator Credits (Millions)	Share of Monthly Balancing Generator Credits	Day Ahead Lost Opportunity Cost Credits (Millions)	Share of Monthly Day Ahead Lost Opportunity Cost Credits
Jan	$0.0	0.1%	$1.1	28.6%	$0.3	13.4%
Feb	$0.0	0.0%	$0.7	19.3%	$0.2	33.7%
Mar	$0.0	0.0%	$1.1	26.4%	$0.1	11.6%
Total (Jan - Mar)	$0.0	0.0%	$2.9	25.0%	$0.5	16.8%

Table 4-34 shows the day-ahead, balancing generator credits, and day-ahead lost opportunity cost credits for combustion turbines by month, also included in Table 4-33.

Table 4-34 Day-ahead operating reserves, balancing operating reserves, day-ahead lost opportunity cost credits for fast start combustion turbines: January through March, 2023

Month	Day-Ahead Operating Reserves	Share of Monthly Day-Ahead Operating Reserves	Balancing Generator Credits	Share of Monthly Day Ahead Operating Reserves	Day Ahead Lost Opportunity Cost Credits	Share of Monthly Day Ahead Lost Opportunity Cost Credits
Jan	$0.0	0.1%	$1.1	27.1%	$0.2	10.9%
Feb	$0.0	0.0%	$0.6	18.4%	$0.2	25.9%
Mar	$0.0	0.0%	$1.1	25.3%	$0.1	10.0%
Total (Jan - Mar)	$0.0	0.0%	$2.9	25.0%	$0.5	16.8%

Capacity Market

In PJM, the capacity market exists to make the energy market work. Energy powers lights and computers and air conditioners. Capacity does not power anything. The capacity market needs to define the total MWh of energy that are needed to reliably serve load. The capacity market needs to provide the missing money. A primary reason to have a capacity market is that the energy market does not provide adequate net revenues to provide incentives for entry and for maintaining existing units. The obligation of load serving entities (LSEs) to own capacity equal to the peak demand plus a reserve margin was a longstanding feature of the PJM Operating Agreement before the creation of the PJM markets. The initial impetus to a capacity market in PJM, a request by the Pennsylvania PUC, was to support retail competition by ensuring that small new entrant competitive LSEs would have access to capacity at a competitive price without having to build capacity or purchase capacity bilaterally at monopoly prices. The first, daily capacity market, created in 1999, was replaced in 2007 by the current design based on the recognition that the energy market resulted in a shortfall in net revenues compared to that necessary to attract and retain adequate resources for the reliable operation of the energy market. The exogenous reliability requirement to have a level of capacity in excess of the level that would result from the operation of an energy market alone reduces the level and volatility of energy market prices and reduces the duration of high energy market prices. This reduces net revenue to generation owners which reduces the incentive to invest. But in order for the PJM markets to be self sustaining, the net revenues from PJM energy, ancillary services and capacity markets must be adequate for those resources. That adequacy requires a capacity market. The capacity market plays the essential role of equilibrating the revenues necessary to incent competitive entry and exit of the resources needed for reliability, with the revenues from the energy and ancillary services markets.

The only goal of the detailed design of the capacity market is to ensure that the opportunity for that revenue equilibration exists through a competitive process.

The Capacity Performance (CP) design was a radical change to the capacity market paradigm. The CP design is a failed experiment. The fundamental mistake of the CP design was to attempt to recreate energy market incentives in the capacity market. The CP model was an explicit attempt to bring energy market shortage pricing into the capacity market design. The CP model was designed on the assumption that shortage prices in the energy market were not high enough and needed to be increased via the capacity market.

The challenge is to create a straightforward capacity market design that meets the simple objectives of a capacity market and that does not become a vehicle for energy market incentives or rent seeking or attempts to limit the ways in which specific types of generation participate in PJM markets. Energy market incentives should remain in the energy market.

The PJM market design is based on the must offer and must buy obligations of capacity resources. All capacity resources, with the current exception of intermittent and storage capacity, are required to offer into the capacity auctions. All LSEs must buy capacity equal to their peak load plus a reserve margin.

Each organization serving PJM load must meet its capacity obligations through the PJM Capacity Market, where load serving entities (LSEs) must pay the locational capacity price for their zone. LSEs can also construct generation and offer it into the capacity market, enter into bilateral contracts, develop demand resources and energy efficiency (EE) resources and offer them into the capacity market, or construct transmission upgrades and offer them into the capacity market.

The Market Monitoring Unit (MMU) analyzed market structure, participant conduct and market performance in the PJM Capacity Market, including supply, demand, concentration ratios, pivotal suppliers, volumes, prices, outage rates and reliability.[1] The conclusions are a result of the MMU's evaluation of the 2024/2025 Base Residual Auction. The 2024/2025 RPM Base Residual Auction was conducted in 2022, but the results were not posted until February 27, 2023, due to an issue with the DPL South reliability requirement.

1 The values stated in this report for the RTO and LDAs refer to the aggregate level including all nested LDAs unless otherwise specified. For example, RTO values include the entire PJM market and all LDAs. Rest of RTO values are RTO values net of nested LDA values.

Table 5-1 The capacity market results were competitive

Market Element	Evaluation	Market Design
Market Structure: Aggregate Market	Not Competitive	
Market Structure: Local Market	Not Competitive	
Participant Behavior	Competitive	
Market Performance	**Competitive**	Mixed

- The aggregate market structure was evaluated as not competitive. For almost all auctions held from 2007 to the present, the PJM capacity market failed the three pivotal supplier test (TPS), which is conducted at the time of the auction.[2] Structural market power is endemic to the capacity market.
- The local market structure was evaluated as not competitive. For almost every auction held, all LDAs have failed the TPS test, which is conducted at the time of the auction.[3]
- Participant behavior was evaluated as competitive in the 2024/2025 BRA after the Commission order addressed the definition of the market seller offer cap by eliminating the net CONE times B offer cap and establishing a competitive market seller offer cap of net ACR, effective September 2, 2021.[4] Market power mitigation measures were applied when the capacity market seller failed the market power test for the auction, the submitted sell offer exceeded the defined offer cap, and the submitted sell offer, absent mitigation, would increase the market clearing price.
- Market performance was evaluated as competitive based on the 2024/2025 Base Residual Auction after the Commission order eliminating the net CONE times B offer cap and establishing a competitive market seller offer cap of net ACR, effective September 2, 2021. Although structural market power exists in the capacity market, a competitive outcome can result from the application of market power mitigation rules.
- Market design was evaluated as mixed because while there are many positive features of the Reliability Pricing Model (RPM) design and the capacity performance modifications to RPM, there are several features of the RPM design which still threaten competitive outcomes. These include the definition of DR which permits inferior products to substitute for capacity, the replacement capacity issue, the definition of unit offer parameters, and the inclusion of imports which are not substitutes for internal capacity resources.
- As a result of the fact that the capacity market design was found to be not just and reasonable by FERC and a final market design had not been approved, the 2022/2023 Base Residual Auction was delayed and held in May 2021, and for a number of additional reasons, the 2023/2024 Base Residual Auction was delayed and held in June 2022, the 2024/2025 Base Residual Auction was delayed and held in December 2022, and first and second incremental auctions for the 2022/2023 through 2026/2027 Delivery Years are canceled if within 10 months of the revised BRA schedule.[5]

Overview

RPM Capacity Market

Market Design

The Reliability Pricing Model (RPM) Capacity Market is a forward looking, annual, locational market, with a must offer requirement for Existing Generation Capacity Resources and a must buy requirement for load, with performance incentives, that includes clear market power mitigation rules and that permits the direct participation of demand-side resources.[6] Currently, intermittent and storage resources are exempt from the must offer requirement, although that is not a viable long term design element for the capacity market. The fundamental goal of the must offer requirement is to ensure that the capacity market works and therefore that the energy market works, given that LSEs have a must buy obligation.

2 In the 2008/2009 RPM Third Incremental Auction, 18 participants in the RTO market passed the TPS test. In the 2018/2019 RPM Second Incremental Auction, 35 participants in the RTO market passed the test. In the 2023/2024 RPM Third Incremental Auction, 36 participants in the RTO passed the TPS test.

3 In the 2012/2013 RPM Base Residual Auction, six participants included in the incremental supply of EMAAC passed the TPS test. In the 2014/2015 RPM Base Residual Auction, seven participants in the incremental supply in MAAC passed the TPS test. In the 2021/2022 RPM First Incremental Auction, two participants in the incremental supply in EMAAC passed the TPS test. In the 2021/2022 RPM Second Incremental Auction, two participants in the incremental supply in EMAAC passed the TPS test. In the 2023/2024 RPM Third Incremental Auction, eight participants in MAAC passed the TPS test.

4 176 FERC ¶ 61,137 (2021), *order denying reh'g*, 178 FERC ¶ 61,121 (2022), *appeal pending*, EPSA, et al. v. FERC, Case No. 21-1214, et al. (DC Cir. 2022). The Commission recognized the market power problem and issued an order correcting the PJM tariff, eliminating the prior offer cap and establishing a competitive market seller offer cap set at net ACR, effective September 2, 2021.

5 174 FERC ¶ 61,036 (2021), 177 FERC ¶ 61,050 (2021), 177 FERC ¶ 61,209 (2021).

6 The terms *PJM Region*, *RTO Region* and *RTO* are synonymous in this report and include all capacity within the PJM footprint.

Under RPM, capacity obligations are annual.[7] Base Residual Auctions (BRA) are held for delivery years that are three years in the future. First, Second and Third Incremental Auctions (IA) are held for each delivery year.[8] First, Second, and Third Incremental Auctions are conducted 20, 10, and three months prior to the delivery year.[9] A Conditional Incremental Auction may be held if there is a need to procure additional capacity resulting from a delay in a planned large transmission upgrade that was modeled in the BRA for the relevant delivery year.[10]

The 2023/2024 RPM Third Incremental Auction was conducted in the first three months of 2023. The 2024/2025 RPM Base Residual Auction was conducted in 2022, but the results were not posted until February 27, 2023, due to an issue with the DPL South reliability requirement.[11]

RPM prices are locational and may vary depending on transmission constraints and local supply and demand conditions.[12] Existing generation that qualifies as a capacity resource must be offered into RPM auctions, except for resources owned by entities that elect the fixed resource requirement (FRR) option, and, as a result of Capacity Performance rule changes, except for intermittent and capacity storage resources including hydro. Participation by LSEs is mandatory, except for those entities that elect the FRR option. There is an administratively determined demand curve that defines scarcity pricing levels and that, with the supply curve derived from capacity offers, determines market prices in each BRA. RPM rules provide performance incentives for generation, including the requirement to submit generator outage data and the linking of capacity payments to the level of unforced capacity. The experience with Winter Storm Elliott (Elliott) has made clear that the extremely high penalties created in the CP model are not an effective incentive. Under RPM there are explicit market power mitigation rules that define structural market power, that define offer caps based on the marginal cost of capacity, and that have flexible criteria for competitive offers by new entrants. Market power mitigation is effective only when these definitions are up to date and accurate. Demand resources and energy efficiency resources may be offered directly into RPM auctions and receive the clearing price without mitigation.

Market Structure

- **RPM Installed Capacity.** In the first three months of 2023, RPM installed capacity decreased 77.0 MW or 0.0 percent, from 183,388.8 MW on January 1, to 183,311.8 MW on March 31. Installed capacity includes net capacity imports and exports and can vary on a daily basis.
- **Reserves.** For the 2024/2025 RPM Base Residual Auction, the sum of cleared MW that were considered categorically exempt from the must offer requirement and the cleared MW of DR is 16,403.2 MW, or 97.2 percent of required reserves and 65.7 percent of total reserves. These results suggest that the required reserve margin and the actual reserve margin be considered carefully along with the obligations of the resources that the reserve margin assumes will be available.
- **RPM Installed Capacity by Fuel Type.** Of the total installed capacity on March 31, 2023, 48.0 percent was gas; 23.4 percent was coal; 17.4 percent was nuclear; 4.6 percent was hydroelectric; 2.8 percent was oil; 1.9 percent was wind; 0.4 percent was solid waste; and 1.5 percent was solar.
- **Market Concentration.** In the 2024/2025 RPM Base Residual Auction, all participants in the total PJM market as well as the LDA RPM markets failed the three pivotal supplier (TPS) test.[13] In the 2023/2024 RPM Third Incremental Auctions, 36 participants out of 51 participants in the total PJM market passed the TPS test, eight participants out of 17 participants in the MAAC LDA market passed the TPS test, and all participants in the EMAAC and BGE LDA markets failed the TPS test. Offer caps were applied to all sell offers for resources which were subject to mitigation when the capacity market seller did not pass the test, the submitted sell

7 Effective for the 2020/2021 and subsequent delivery years, the RPM market design incorporated seasonal capacity resources. Summer period and winter period capacity must be matched either through commercial aggregation or through the optimization in equal MW amounts in the LDA or the lowest common parent LDA.
8 See 126 FERC ¶ 61,275 at P 86 (2009).
9 See Letter Order, FERC Docket No. ER10-366-000 (January 22, 2010).
10 See 126 FERC ¶ 61,275 at P 88 (2009). There have been no Conditional Incremental Auctions.
11 On December 23, 2022, PJM filed revisions to the PJM market rules in Docket No. ER23-729-000 and contemporaneously filed a complaint in Docket No. EL23-19-000 seeking the same revisions. By order issued February 21, 2023, PJM's revisions were accepted and the complaint was dismissed as moot. 182 FERC ¶ 61,109.
12 Transmission constraints are local capacity import capability limitations (low capacity emergency transfer limit (CETL) margin over capacity emergency transfer objective (CETO)) caused by transmission facility limitations, voltage limitations or stability limitations.
13 There are 27 Locational Deliverability Areas (LDAs) identified to recognize locational constraints as defined in "Reliability Assurance Agreement Among Load Serving Entities in the PJM Region," Schedule 10.1. PJM determines, in advance of each BRA, whether the defined LDAs will be modeled in the given delivery year using the rules defined in OATT Attachment DD § 5.10(a)(ii).

offer exceeded the defined offer cap, and the submitted sell offer, absent mitigation, increased the market clearing price.[14] [15] [16]

- **Imports and Exports.** Of the 1,527.1 MW of imports in the 2024/2025 RPM Base Residual Auction, 1,397.6 MW cleared. Of the cleared imports, 820.4 MW (58.7 percent) were from MISO.
- **Demand-Side and Energy Efficiency Resources.** Capacity in the RPM load management programs was 14,027.0 MW for June 1, 2022, as a result of cleared capacity for demand resources and energy efficiency resources in RPM auctions for the 2022/2023 Delivery Year (14,601.0 MW) less purchases of replacement capacity (574.0 MW).

Market Conduct

- **2024/2025 RPM Base Residual Auction.** Of the 964 generation resources that submitted Capacity Performance offers, the MMU calculated unit specific offer caps for 22 generation resources (2.3 percent).
- **2023/2024 RPM Third Incremental Auction.** Of the 250 generation resources that submitted Capacity Performance offers, the MMU calculated unit specific offer caps for five generation resources (2.0 percent).

Market Performance

- The 2023/2024 RPM Third Incremental Auction was conducted in the first three months of 2023. The 2024/2025 RPM Base Residual Auction was conducted in 2022, but the results were not posted until February 27, 2023, due to an issue with the DPL South reliability requirement. The weighted average capacity price for the 2022/2023 Delivery Year is $72.33 per MW-day, including all RPM auctions for the 2022/2023 Delivery Year. The weighted average capacity price for the 2023/2024 Delivery Year is $42.00 per MW-day, including all RPM auctions for the 2023/2024 Delivery Year held through the first three months of 2023. The weighted average capacity price for the 2024/2025 Delivery Year is $40.73 per MW-day, including all RPM auctions for the 2024/2025 Delivery Year held through the first three months of 2023.
- For the 2022/2023 Delivery Year, RPM annual charges to load are $4.0 billion.
- In the 2024/2025 RPM Base Residual Auction, the market performance was determined to be competitive.

Part V Reliability Service

- Of the eight companies (24 units) that have provided service following deactivation requests, two companies (seven units) filed to be paid under the deactivation avoidable cost rate (DACR), the formula rate. The other six companies (17 units) filed to be paid under the cost of service recovery rate.

Generator Performance

- **Forced Outage Rates.** The average PJM EFORd in the first three months of 2023 was 4.7 percent, a decrease from 6.1 percent in the first three months of 2022.[17]
- **Generator Performance Factors.** The PJM aggregate equivalent availability factor in the first three months of 2023 was 86.6 percent, an increase from 86.5 percent in the first three months of 2022.

Recommendations[18]

Definition of Capacity

- The MMU recommends elimination of the key remaining components of the CP model because they interfere with competitive outcomes in the capacity market and create unnecessary complexity and risk. (Priority: High. First reported Q3, 2022. Status: Not adopted.)

14 See OATT Attachment DD § 6.5.

15 Prior to November 1, 2009, existing DR and EE resources were subject to market power mitigation in RPM Auctions. See 129 FERC ¶ 61,081 at P 30 (2009).

16 Effective January 31, 2011, the RPM rules related to market power mitigation were changed, including revising the definition for Planned Generation Capacity Resource and creating a new definition for Existing Generation Capacity Resource for purposes of the must offer requirement and market power mitigation, and treating a proposed increase in the capability of a generation capacity resource the same in terms of mitigation as a Planned Generation Capacity Resource. See 134 FERC ¶ 61,065 (2011).

17 The generator performance analysis includes all PJM capacity resources for which there are data in the PJM generator availability data systems (GADS) database. Data was downloaded from the PJM GADS database on April 24, 2023. EFORd data presented in state of the market reports may be revised based on data submitted after the publication of the reports as generation owners may submit corrections at any time with permission from PJM GADS administrators.

18 The MMU has identified serious market design issues with RPM and the MMU has made specific recommendations to address those issues. These recommendations have been made in public reports. See Table 5-2.

- The MMU recommends the enforcement of a consistent definition of capacity resources. The MMU recommends that the requirement to be a physical resource be enforced and enhanced. The requirement to be a physical resource should apply at the time of auctions and should also constitute a commitment to be physical in the relevant delivery year. The requirement to be a physical resource should be applied to all resource types, including planned generation, demand resources and imports.[19] [20] (Priority: High. First reported 2013. Status: Not adopted.)
- The MMU recommends that DR providers be required to have a signed contract with specific customers for specific facilities for specific levels of DR at least six months prior to any capacity auction in which the DR is offered. (Priority: High. First reported 2016. Status: Not adopted.)
- The MMU recommends that Energy Efficiency Resources (EE) not be included in the capacity market because PJM's load forecasts now account for EE, unlike the situation when EE was first added to the capacity market.[21] (Priority: Medium. First reported 2016. Status: Not adopted.)
- The MMU recommends that intermittent resources, including storage, not be permitted to offer capacity MW based on energy deliveries that exceed their defined deliverability rights (CIRs). Only energy output for such resources below the designated CIR/deliverability level should be recognized in the definition of derated capacity (e.g. ELCC). Correctly defined derating factors will be lower than the CIRs required to meet those derating factors. (Priority: High. First reported 2021. Status: Not adopted.)
- The MMU recommends that PJM require all market participants to meet their deliverability requirements under the same rules. PJM should end the practice of giving away winter CIRs that appear to exist because other resources paid for the supporting network upgrades. (Priority: High. First reported 2017. Status: Not adopted.)[22]

19 See also Comments of the Independent Market Monitor for PJM, Docket No. ER14-503-000 (December 20, 2013).
20 See "Analysis of Replacement Capacity for RPM Commitments: June 1, 2007 to June 1, 2019," <http://www.monitoringanalytics.com/reports/Reports/2019/IMM_Analysis_of_Replacement_Capacity_for_RPM_Commitments_June_1_2007_to_June_1_2019_20190913.pdf> (September 13, 2019).
21 "PJM Manual 19: Load Forecasting and Analysis," § 3.2 Development of the Forecast, Rev. 35 (Dec. 31, 2021).
22 This recommendation was first made in the 2020/2021 BRA report in 2017. See the "Analysis of the 2020/2021 RPM Base Residual Auction," <http://www.monitoringanalytics.com/reports/Reports/2017/IMM_Analysis_of_the_20202021_RPM_BRA_20171117.pdf> (November 11, 2017).

- The MMU recommends that the must offer rule in the capacity market apply to all capacity resources. There is no reason to exempt intermittent and capacity storage resources, including hydro, and demand resources and energy efficiency resources from the must offer requirement. The same rules should apply to all capacity resources. (Priority: High. First reported 2021. Status: Not adopted.)

Market Design and Parameters

- The MMU recommends that PJM reevaluate the shape of the VRR curve. The shape of the VRR curve directly results in load paying substantially more for capacity than load would pay with a vertical demand curve. More specifically, the MMU recommends that the VRR curve be rotated half way towards the vertical demand curve at the reliability requirement for the current Quadrennial Review. (Priority: High. First reported 2021. Status: Partially adopted.)
- The MMU recommends that the maximum price on the VRR curve be defined as net CONE. (Priority: Medium. First reported 2019. Status: Not adopted.)
- The MMU recommends that the test for determining modeled Locational Deliverability Areas (LDAs) in RPM be redefined. A detailed reliability analysis of all at risk units should be included in the redefined model. (Priority: Medium. First reported 2013. Status: Not adopted.)
- The MMU recommends that PJM clear the capacity market based on nodal capacity resource locations and the characteristics of the transmission system consistent with the actual electrical facts of the grid. Absent a fully nodal capacity market clearing process, the MMU recommends that PJM use a non-nested model with all LDAs modeled including VRR curves for all LDAs. Each LDA requirement should be met with the capacity resources located within the LDA and exchanges from neighboring LDAs up to the transmission limit. LDAs should be allowed to price separate if that is the result of the LDA supply curves and the transmission constraints between LDAs. (Priority: Medium. First reported 2017. Status: Not adopted.)

- The MMU recommends the use of a forward looking energy and ancillary services (E&AS) net revenue offset rather than the backward looking E&AS net revenue offset currently in the tariff. Forward prices for energy prices and fuel costs are a better guide to market expectations of net revenues than an average of the actual net revenues for the last three years. (Priority: High. First reported 2014. Status: Not adopted.)[23]
- The MMU recommends that PJM reduce the number of incremental auctions to a single incremental auction held three months prior to the start of the delivery year and reevaluate the triggers for holding conditional incremental auctions. (Priority: Medium. First reported 2013. Status: Not adopted.)
- The MMU recommends that PJM not sell back any capacity in any IA procured in a BRA. If PJM continues to sell back capacity, the MMU recommends that PJM offer to sell back capacity in incremental auctions only at the BRA clearing price for the relevant delivery year. (Priority: Medium. First reported 2017. Status: Not adopted.)
- The MMU recommends changing the RPM solution method to explicitly incorporate the cost of uplift (make whole) payments in the objective function. (Priority: Medium. First reported 2014. Status: Not adopted.)
- The MMU recommends that the Fixed Resource Requirement (FRR) rules, including obligations and performance requirements, be revised and updated to ensure that the rules reflect current market realities and that FRR entities do not unfairly take advantage of those customers paying for capacity in the PJM capacity market. (Priority: Medium. First reported 2019. Status: Not adopted.)
- The MMU recommends that the value of CTRs should be defined by the total MW cleared in the capacity market, the internal MW cleared and the imported MW cleared, and not redefined later prior to the delivery year. (Priority: Medium. First reported 2021. Status: Not adopted.)
- The MMU recommends that the market clearing results be used in settlements rather than the reallocation process currently used, or that the process of modifying the obligations to pay for capacity be reviewed. (Priority: Medium. First reported 2021. Status: Not adopted.)
- The MMU recommends that PJM improve the clarity and transparency of its CETL calculations. The MMU also recommends that CETL for capacity imports into PJM be based on the ability to import capacity only where PJM capacity exists and where that capacity has a must offer requirement in the PJM Capacity Market. (Priority: Medium. First reported 2021. Status: Partially adopted 2022.)
- The MMU recommends that the value of CTRs be defined by the total MW cleared in the capacity market, the internal MW cleared and the imported MW cleared, and not redefined later prior to the delivery year. Capacity Transfer Rights (CTRs) are used to return capacity market congestion revenues to load, but the CTRs that result from market clearing prices and quantities are not included in final settlements for individual LDAs. MMU also recommends that the market clearing results be used in settlements rather than the reallocation process currently used or that the process of modifying the obligations to pay for capacity be reviewed. (Priority: High. First reported 2022. Status: Not adopted.)[24]

Offer Caps, Offer Floors, and Must Offer

- The MMU recommends using the lower of the cost or price-based energy market offer to calculate energy costs in the calculation of the historical net revenues which are an offset to gross ACR in the calculation of unit specific capacity resource offer caps based on net ACR. (Priority: Medium. First reported 2021. Status: Not adopted.)
- The MMU recommends use of the Sustainable Market Rule (SMR) in order to protect competition in the capacity market from nonmarket revenues.[25] (Priority: High. First reported 2016. Status: Not adopted.)
- The MMU recommends that, as part of the MOPR unit specific standard of review, all projects be required to use the same basic modeling assumptions. That is the only way to ensure that projects compete on the

23 This recommendation was first made during the Quadrennial Review in 2014, including the PJM Capacity Senior Task Force (CSTF), the MRC and the MC. <https://www.pjm.com/committees-and-groups/closed-groups/cstf>.

24 This recommendation first made in the 2023/2024 BRA report in 2022. See "Analysis of the 2023/2024 RPM Base Residual Auction Revised," <http://www.monitoringanalytics.com/reports/Reports/2022/IMM_Analysis_of_the_20232024_RPM_Base_Residual_Auction_20221028.pdf> (October 28, 2022).

25 Brief of the Independent Market Monitor for PJM, Docket No. EL16-49, ER18-1314-000,-001; EL18-178 (October 2, 2018).

basis of actual costs rather than on the basis of modeling assumptions.[26] (Priority: High. First reported 2013. Status: Not adopted.)

- The MMU recommends that modifications to existing resources be subject to market power related offer caps or MOPR offer floors and not be treated as new resources and therefore exempt. (Priority: Low. First reported 2012. Status: Not adopted.)
- The MMU recommends that the RPM market power mitigation rule be modified to apply offer caps in all cases when the three pivotal supplier test is failed and the sell offer is greater than the offer cap. This will ensure that market power does not result in an increase in uplift (make whole) payments for seasonal products. (Priority: Medium. First reported 2017. Status: Not adopted.)
- The MMU recommends that any combined seasonal resources be required to be in the same LDA and preferably at the same location, in order for the energy market and capacity market to remain synchronized and reliability metrics correctly calculated. (Priority: Medium. First reported 2021. Status: Not adopted.)
- The MMU recommends that the definition of avoidable costs in the tariff be corrected to be consistent with the economic definition. Avoidable costs are costs that are neither short run marginal costs, like fuel or consumables, nor fixed costs like depreciation and rate of return. Avoidable costs are the annual marginal costs of capacity and therefore the competitive offer level for capacity resources and therefore the market seller offer cap. Avoidable costs are the annual marginal costs of capacity whether a new resource or an existing resource. (Priority: Medium. First reported 2017. Status: Not adopted.)[27]
- The MMU recommends that capacity market sellers be required to explicitly request and support the use of minimum MW quantities (inflexible sell offer segments) and that the requests only be permitted for defined physical reasons. (Priority: Medium. First reported 2018. Status: Not adopted.)
- The MMU recommends that relatively small proposed increases in the capability of a Generation Capacity Resource be treated as an existing resource and subject to the corresponding market power mitigation rules and no longer be treated as planned and exempt from offer capping. (Priority: Medium. First reported 2012. Status: Not adopted.)[28]

Performance Incentive Requirements of RPM

- The MMU recommends that any unit not capable of supplying energy equal to its day-ahead must offer requirement (ICAP) be required to reflect an appropriate outage. (Priority: Medium. First reported 2009. Status: Not adopted.)
- The MMU recommends that retroactive replacement transactions associated with a failure to perform during a PAI not be allowed and that, more generally, retroactive replacement capacity transactions not be permitted. (Priority: Medium. First reported 2016. Status: Not adopted.)
- The MMU recommends that there be an explicit requirement that capacity resource offers in the day-ahead energy market be competitive, where competitive is defined to be the short run marginal cost of the units, including flexible operating parameters. (Priority: Low. First reported 2013. Status: Not adopted.)
- The MMU recommends that Capacity Performance resources be required to perform without excuses. Resources that do not perform should not be paid regardless of the reason for nonperformance. (Priority: High. First reported 2019. Status: Not adopted.)
- The MMU recommends that the market data posting rules be modified to allow the disclosure of expected performance, actual performance,

26 See 143 FERC ¶ 61,090 (2013) ("We encourage PJM and its stakeholders to consider, for example, whether the unit-specific review process would be more effective if PJM requires the use of common modeling assumptions for establishing unit-specific offer floors while, at the same time, allowing sellers to provide support for objective, individual cost advantages. Moreover, we encourage PJM and its stakeholders to consider these modifications to the unit-specific review process together with possible enhancements to the calculation of Net CONE."); see also, Comments of the Independent Market Monitor for PJM, Docket No. ER13-535-001 (March 25, 2013); Complaint of the Independent Market Monitor for PJM v. Unnamed Participant, Docket No. EL12-63-000 (May 1, 2012); Motion for Clarification of the Independent Market Monitor for PJM, Docket No. ER11-2875-000, et al. (February 17, 2012); Protest of the Independent Market Monitor for PJM, Docket No. ER11-2875-002 (June 2, 2011); Comments of the Independent Market Monitor for PJM, Docket Nos. EL11-20 and ER11-2875 (March 4, 2011).

27 This recommendation was first made in the 2023/2024 BRA report in 2022. See "Analysis of the 2023/2024 RPM Base Residual Auction Revised," <http://www.monitoringanalytics.com/reports/Reports/2022/IMM_Analysis_of_the_20232024_RPM_Base_Residual_Auction_20221028.pdf> (October 28, 2022).

28 This recommendation was first made in the 2014/2015 BRA report in 2012. See "Analysis of the 2014/2015 RPM Base Residual Auction," <http://www.monitoringanalytics.com/reports/Reports/2012/Analysis_of_2014_2015_RPM_Base_Residual_Auction_20120409.pdf> (April 9, 2012).

shortfall and bonus MW during a PAI by area without the requirement that more than three market participants' data be aggregated for posting. (Priority: Low. First reported 2019. Status: Not adopted.)

- The MMU recommends that PJM require actual seasonal tests as part of the Summer/Winter Capability Testing rules, that the number of tests be limited, and that the ambient conditions under which the tests are performed be defined. (Priority: Medium. First reported Q1 2022. Status: Not adopted.)
- The MMU recommends that PJM select the time and day that a unit undergoes Net Capability Verification Testing, not the unit owner, and that this information not be communicated in advance to the unit owner. (Priority: Medium. First reported Q2 2022. Status: Not adopted.)

Capacity Imports and Exports

- The MMU recommends that all capacity imports be required to be deliverable to PJM load in an identified LDA, zonal or smaller, or explicit combinations of specific zones, e.g. MAAC, prior to the relevant delivery year to ensure that they are full substitutes for internal, physical capacity resources. Pseudo ties alone are not adequate to ensure deliverability to PJM load. (Priority: High. First reported 2016. Status: Not adopted.)
- The MMU recommends that all costs incurred as a result of a pseudo tied unit be borne by the unit itself and included as appropriate in unit offers in the capacity market. (Priority: High. First reported 2016. Status: Not adopted.)

Deactivations/Retirements

- The MMU recommends that the notification requirement for deactivations be extended from 90 days prior to the date of deactivation to 12 months prior to the date of deactivation and that PJM and the MMU be provided 60 days rather than 30 days to complete their reliability and market power analyses. (Priority: Low. First reported 2012. Status: Partially adopted.)
- The MMU recommends that units recover all and only the incremental costs, including incremental investment costs, required by the Part V reliability service (RMR service) that the unit owner would not have incurred if the unit owner had deactivated its unit as it proposed. Customers should bear no responsibility for paying previously incurred costs, including a return on or of prior investments. (Priority: Low. First reported 2010. Status: Not adopted.)
- The MMU recommends elimination of the cost of service recovery rate in OATT Section 119, that Part V reliability service (RMR) should be provided under the deactivation avoidable cost rate in Part V, and that the cap on investment under the avoidable cost rate option be eliminated. The MMU also recommends specific improvements to the DACR provisions. (Priority: Medium. First reported 2017. Status: Not adopted.)

Conclusion

The analysis of PJM Capacity Markets begins with market structure, which provides the framework for the actual behavior or conduct of market participants. The analysis examines participant behavior within that market structure. In a competitive market structure, market participants are constrained to behave competitively. In a market with endemic structural market power, effective market power mitigation rules are required in order to constrain market participants to behave competitively. The analysis examines market performance, measured by price and the relationship between price and marginal cost, that results from the interaction of market structure and participant behavior.

The capacity market is, by design, always tight in the sense that total supply is generally only slightly larger than demand. The PJM Capacity Market is a locational market and local markets can and do have different supply demand balances than the aggregate market. While the market may be long at times, that is not the equilibrium state. Capacity in excess of demand is not sold and, if it does not earn or does not expect to earn adequate revenues in future capacity markets, or in other markets, or does not have value as a hedge, may be expected to retire, provided the market sets appropriate price signals to reflect the availability of excess supply. The demand for capacity includes expected peak load plus a reserve margin, and points on the demand curve, called the Variable Resource Requirement (VRR) curve, exceed peak load plus the reserve margin. The shape of the VRR curve results in the purchase of excess capacity and higher payments by customers. The impact of the VRR curve shape used in the 2023/2024 BRA compared to a vertical demand curve was a significant increase in customer payments for load as a result of buying more capacity than needed for reliability and paying a price above the competitive level as a result. The defined reliability goal is to have total supply greater than or equal to the defined demand for capacity. The level of purchased demand under RPM has generally exceeded expected peak load plus the target reserve margin, resulting in reserve margins that exceed the target. Demand for capacity is almost entirely inelastic because the market rules require loads to purchase their share of the system capacity requirement. The VRR demand curve is everywhere inelastic. The result is that any supplier that owns more capacity than the typically small difference between total supply and the defined demand is individually pivotal and therefore has structural market power. Any supplier that, jointly with two other suppliers, owns more capacity than the difference between supply and demand either in aggregate or for a local market is jointly pivotal and therefore has structural market power.

For the 2024/2025 RPM Base Residual Auction, the level of committed demand resources (8,083.9 MW UCAP) almost equals the entire level of excess capacity (8,086.8 MW). This is consistent with PJM effectively not relying on demand response for reliability in actual operations. The excess is a result of the flawed rules permitting the participation of inferior demand side resources in the capacity market. Maintaining the persistent excess has meant that PJM markets have never experienced the results of reliance on demand side resources as part of the required reserve margin, rather than as excess above the required reserve margin. PJM markets have never experienced the implications of the definition of demand side resources as a purely emergency capacity resource that triggers a PAI whenever called and can set prices at shortage levels simply by being called.

The market design for capacity leads to structural market power in the capacity market. The capacity market is unlikely ever to approach a competitive market structure in the absence of a substantial and unlikely structural change that results in much greater diversity of ownership. Market power is and will remain endemic to the structure of the PJM Capacity Market. Nonetheless a competitive outcome can be assured by appropriate market power mitigation rules. Detailed market power mitigation rules are included in the PJM Open Access Transmission Tariff (OATT or Tariff). Reliance on the RPM design for competitive outcomes means reliance on the market power mitigation rules. Attenuation of those rules means that market participants are not able to rely on the competitiveness of the market outcomes. The market power rules applied in the 2021/2022 BRA and the 2022/2023 BRA were significantly flawed, as illustrated by the results of the 2021/2022 BRA and the 2022/2023 BRA.[29] [30] Competitive outcomes require continued improvement of the rules and ongoing monitoring of market participant behavior and market performance. The incorrect definition of the offer caps in the 2021/2022 BRA and the 2022/2023 BRA resulted in noncompetitive offers and a noncompetitive outcome. The market power rules were corrected by the Commission in an order issued on September 2, 2021, but the modified market power rules were not implemented in the 2022/2023 BRA.[31] [32] The result was that capacity market prices were above the competitive level in the 2022/2023 BRA. In addition, the inclusion of offers that were not consistent with the defined terms of the Minimum Offer Price Rule (MOPR) based on the MMU's review, but were accepted by PJM, had a significant impact on the auction results in the 2022/2023 BRA.

The implementation of the market power mitigation rules effective September 2, 2021, that corrected the definition of the market seller offer cap in the 2023/2024 BRA resolved the market power issues from the prior two BRAs. The results of the 2023/2024 BRA and the 2024/2025 BRA were competitive.

In the capacity market, as in other markets, market power is the ability of a market participant to increase the market price above the competitive level or to decrease the market price below the competitive level. In order to evaluate whether actual prices reflect the exercise of market power, it is necessary to evaluate whether market offers are consistent with competitive offers.

29 See "Analysis of the 2021/2022 RPM Base Residual Auction - Revised," <http://www.monitoringanalytics.com/reports/Reports/2018/IMM_Analysis_of_the_20212022_RPM_BRA_Revised_20180824.pdf> (August 24, 2018).
30 See "Analysis of the 2022/2023 RPM Base Residual Auction," <https://www.monitoringanalytics.com/reports/Reports/2022/IMM_Analysis_of_the_20222023_RPM_BRA_20220222.pdf> (February 22, 2022).
31 Complaint of the Independent Market Monitor for PJM, Docket No. EL19-47 (February 21, 2019) ("IMM MSOC Complaint").
32 176 FERC ¶ 61,137 (2021); 178 FERC ¶ 61,121 (2022); *appeal pending*, Vistra Corp., et al. v. FERC, USCA D.C. Circuit Case No. 21-1214.

The definition of the market seller offer cap was changed with the introduction of the Capacity Performance (CP) rules, from offer caps based on the marginal cost of capacity to offer caps based on Net CONE. But the CP market seller offer cap was based on strong assumptions that are not correct. The derivation of the CP market seller offer cap was based on PJM's assertion that the target price of the capacity market should be Net CONE, and simply assumed the answer. The logic underlying the CP market seller offer cap was circular. The CP market seller offer cap was incorrectly and significantly overstated as a result.

PJM's filing of the CP design made clear that PJM was abandoning offer caps that were based on verifiable calculations of the marginal cost of providing capacity in favor of an approach that explicitly relied on wishful thinking about competitive forces resulting in competitive offers, despite the fact that the filing elsewhere recognized the high levels of concentration and the need to protect against market power in the capacity market.[33] PJM ignored the economic logic of marginal cost. PJM simply asserted that Net CONE was the target clearing price of the capacity market. PJM's filing explicitly stated that "By design, over time the marginal offer needed to clear the market will be priced at Net CONE, and all other resources that clear the market will be compensated at that Net CONE price."[34] PJM did not include a derivation of the offer cap in its CP filing, but simply asserted that Net CONE was the definition of a competitive offer.[35] There was not a single reference to opportunity cost as the basis for the market seller offer cap in the PJM filing.

In subsequent filings, PJM included the mathematical derivation of the market seller offer cap.[36] But the circular logic of the derivation inevitably concluded that Net CONE times B was the competitive offer. There were two key assumptions that led to that result. The derivation started by assuming that Net CONE was the target clearing price for the capacity market. PJM stated, in explaining the penalty rate, "Net CONE is the proper measure of the value of capacity."[37] That assumption/assertion was the basis for using Net CONE as the penalty rate. The penalty rate, adjusted for the reduced obligation defined by B, became the market seller offer cap. In addition to assuming the answer by setting the penalty rate based on net CONE, the second key counterfactual assumption was that capacity resources have the ability to costlessly switch between capacity resource status and energy only status.

The mathematical derivation also included some additional unsupported and incorrect assumptions: there are a reasonably expected number of PAI; the number of PAI used in the calculation of the nonperformance charge rate is the same as the expected PAI (360); the number of performance intervals that define the total payments must equal the denominator of the performance penalty rate; the bonus payment rate for units that overperform equals the penalty rate for units that underperform; and penalties are imposed by PJM for all cases of noncompliance as defined in the tariff and there are no excuses.

Those assumptions were not even close to being correct for the 2022/2023 BRA and Net CONE times B was not the correct offer cap as a result.

The MMU supported the modified CP filing and prepared the mathematical appendix.[38] But, after evaluating the offer behavior and results of the capacity market auctions under CP and the actual PAI evidence and the failure to include updated PAI data in the definition of the offer cap, it became clear to the MMU that the CP model was a mistake.[39] The market seller offer cap of Net CONE times B was ultimately a failed experiment based on the third demonstrably false assumption that competitive forces in the PJM Capacity Market would produce competitive outcomes despite an offer cap that was above the competitive level. The structure of the PJM Capacity Market is not competitive and the purpose of market power mitigation is to produce competitive results despite that fact. The Net CONE times B offer cap assumed competition where it did not exist and led to noncompetitive outcomes and led to customers being overcharged by a combined $1.454 billion in the 2021/2022 and 2022/2023 BRAs.[40] The logical circularity of the argument as

33 See "Reforms to the Reliability Pricing Market ("RPM") and Related Rules in the PJM Open Access Transmission Tariff ("Tariff") and Reliability Assurance Agreement Among Load Serving Entities ("RAA")," ("CP Filing"), Docket No. ER15-623, December 12, 2014; See, for example, page 54 and page 58.

34 See page 55 of CP Filing.

35 PJM did not multiply Net CONE by B in its CP filing of December 12, 2014.

36 For a detailed derivation, *see* Errata to February 25, 2015 Answer and Motion for Leave to Answer of the Independent Market Monitor for PJM Interconnection, L.L.C., Docket No. ER15-623, et al. (February 27, 2015).

37 See page 43 of CP Filing.

38 See PJM Response to Deficiency Notice, ER15-623-001, et al. (April 10, 2015); Comments of the Independent Market Monitor for PJM, Docket No. ER15-623-001, et al. (April 15, 2015).

39 Brief of the Independent Market Monitor for PJM, EL19-47-000 (April 28, 2021); see also Comments of the Independent Market Monitor, Docket No. ER15-623, EL15-29 and EL19-47 (December 13, 2019); Comments of the Independent Market Monitor, Docket No. ER15-623, EL15-29 and EL19-47 (December 17, 2020).

40 See "Analysis of the 2021/2022 RPM Base Residual Auction - Revised," <http://www.monitoringanalytics.com/reports/Reports/2018/IMM_Analysis_of_the_20212022_RPM_BRA_Revised_20180824.pdf> (August 24, 2018) and "Analysis of the 2022/2023 RPM Base Residual Auction," <http://www.monitoringanalytics.com/reports/Reports/2022/IMM_Analysis_of_the_20222023_RPM_BRA_20220222.pdf>.

well as the fact that key assumptions are incorrect, means that the CP market seller offer cap was not based on economics or logic or math.

The correct definition of a competitive offer is the marginal cost of capacity, net ACR, where ACR includes an explicit accounting for the costs of mitigating risk, including the risk associated with capacity market nonperformance penalties, and the relevant costs of acquiring fuel, including natural gas. In response to a complaint filed by the MMU, the Commission replaced the Net CONE times B market seller offer cap with an ACR offer cap in the September 2nd Order.[41] [42]

The MMU recommends elimination of the key remaining components of the CP model because they interfere with competitive outcomes in the capacity market and create unnecessary complexity and risk. The use of Net CONE as the basis for the penalty rate is unsupported by economic logic. The use of Net CONE to establish penalties is a form of arbitrary administrative pricing that creates arbitrarily high risk for generators, creates complexity in the calculation of CPQR and ultimately raises the price of capacity. Rather than penalizing capacity resources for nonperformance, capacity resources should be paid the daily price of capacity only to the extent that they are available to produce energy or provide reserves, as required by PJM on a daily/hourly basis, based on their cleared capacity (ICAP). This is a positive performance incentive based on the market price of capacity rather than a penalty based on an arbitrary assumption. This would mean that capacity resources are paid to provide energy and reserves based on their full ICAP and are not paid a bonus for doing so. The reduced payments for capacity would directly reduce customers' bills for capacity. This would also end the pretense that there will be penalty payments to fund bonus payments. This would also end the need for complex CPQR calculations based on the penalty rate and assumptions about the number and timing of PAI. CP has not worked as the theory suggested. There have been only de minimis and generally very local PAI, largely excused nonperformance and de minimis bonus payments. The actual performance standards were unacceptably weakened in the CP model. The standard of performance in the CP model is B * (1 – EFORd) for a unit, where B is the balancing ratio and EFORd is the forced outage rate. For example, if B were 80 percent, the actual required performance for a unit with a 10 percent EFORd would be only 72 percent of ICAP (.80 * .90). For units with high historical forced outage rates, the required performance is even lower. The obligation to perform should equal the full ICAP value of a unit, consistent with the associated must offer obligation in the energy market for capacity resources.

The fundamental mistake of the CP design was to attempt to recreate energy market incentives in the capacity market. The CP model was an explicit attempt to bring energy market shortage pricing into the capacity market design. The CP model was designed on the assumption that shortage prices in the energy market were not high enough and needed to be increased via the capacity market. The CP design focused on a small number of critical hours (performance assessment hours or PAH, translated into five minute intervals as PAI) and imposed large penalties on generators that failed to produce energy only during those hours. But the use of capacity market penalties rather than energy market incentives created risk. While there are differences of opinion about how to value the risk, this CP risk is not risk that is fundamental to the operation of a wholesale power market. This is risk created by the CP design in order, in concept, to provide an incentive to produce energy during high demand hours that is even higher than the energy market incentive, amplified by an operating reserve demand curves (ORDC). The potential risk created by CP is not limited to risk for individual generators, but extends to the viability of the market. If penalties create bankruptcies that threaten the viability of required energy output from the affected units, there is a risk to the market.

Winter storm Elliott provided the first real test of the CP design. Elliott showed that the CP design does not provide effective incentives. There was an extremely high forced outage level during Elliott despite the incentives and despite the fact that the effectively uncapped market seller offer cap (MSOC) was in place (Net CONE times B) for RPM auctions conducted for the 2022/2023 Delivery Year. In addition, it has been clear from prior, very brief and local PAI events that the process of defining excuses and retroactive replacement transactions, imposing penalties and paying bonuses is complex and very difficult to

41 Complaint of the Independent Market Monitor for PJM, Docket No. EL19-47, February 21, 2019 ("IMM MSOC Complaint").
42 174 FERC ¶ 61,212; 176 FERC ¶ 61,137; *order on reh'g*, 178 FERC ¶ 61,121.

administer, and includes substantial subjective elements. PAI incentives are not effective market incentives. PAI incentives are administrative and nonmarket incentives not compatible with an effective market design. The energy market clearing, in contrast, is transparent and efficient and timely. While there are issues with the details of energy market pricing that must be addressed, including shortage pricing, the energy market does not include or create the significant and long lasting uncertainty created by the PAI rules as exhibited most dramatically by the results of Elliott. The PAI design creates an administrative process that adds unacceptable uncertainty to the process and that can never approach the effectiveness of the energy market in providing price signals and timely settlement.

The MMU concludes that the results of the 2024/2025 RPM Base Residual Auction were competitive. A competitive offer in the capacity market is equal to net ACR.[43] The ACR values were based on data provided by the participants and were consistent with competitive offers for the relevant capacity.

The MMU also concludes that market prices were significantly affected by flaws in the capacity market rules and in the application of the capacity market rules by PJM, including the shape of the VRR curve; the overstatement of intermittent MW offers; the inclusion of sell offers from DR; and capacity imports.

The MMU also concludes that, although not an issue in the 2024/2025 Base Residual Auction, the rules permit the exercise of market power without mitigation for seasonal products through uplift payments for noncompetitive offers, rather than through higher prices.[44] Although the impact did not arise in the 2024/2025 Base Residual Auction, the issue should be addressed immediately in order to prevent the impact from increasing and because the solution is simple.

Changes to the capacity market design have addressed some but not all of the significant recommendations made by the MMU in prior reports. The MMU had recommended the elimination of the 2.5 percent demand adjustment (Short-Term Resource Procurement Target). The MMU had recommended that the performance incentives in the capacity market design be strengthened. The MMU had recommended that generation capacity resources pay penalties if they fail to produce energy when called upon during any of the hours defined as critical. The MMU had recommended that the net revenue calculation used by PJM to calculate the Net Cost of New Entry (CONE) VRR parameter reflect the actual flexibility of units in responding to price signals rather than using assumed fixed operating blocks that are not a result of actual unit limitations. The MMU had recommended that all capacity imports be required to be pseudo tied in order to ensure that imports are as close to full substitutes for internal, physical capacity resources as possible. The MMU had recommended that the definition of demand side resources be modified in order to ensure that such resources are full substitutes for and provide the same value in the capacity market as generation resources, although this recommendation has not been incorporated in PJM rules. The MMU had recommended that both the Limited and the Extended Summer DR products be eliminated and that the restrictions on the availability of Annual DR be eliminated in order to ensure that the DR product has the same unlimited obligation to provide capacity year round as Generation Capacity Resources. The MMU had recommended that the EE addback calculation be corrected. The MMU had recommended that the default Avoidable Cost Rate (ACR) escalation method be modified in order to ensure accuracy and eliminate double counting.

The MMU is required to identify market issues and to report them to the Commission and to market participants. The Commission decides on any action related to the MMU's findings.

43 174 FERC ¶ 61,212 ("March 18th Order") at 65.

44 PJM uses various terms for uplift including make whole payments (often used in the capacity market) and operating reserve payments (often used in the energy market). The term uplift is used in this report to refer to out of market payments made by PJM to market participants in addition to market revenues.

The MMU has identified serious market design issues with RPM and the MMU has made specific recommendations to address those issues.[45] [46] [47] [48] [49] [50] [51] [52] [53] In 2022 and 2023, the MMU prepared a number of RPM related reports and testimony, shown in Table 5-2.

The PJM markets have worked to provide incentives to entry and to retain capacity. PJM had excess reserves of 6,596.3 ICAP MW on June 1, 2022, and will have excess reserves of 8,896.3 ICAP MW on June 1, 2023, based on current positions.[54] A majority of capacity investments in PJM were financed by market sources.[55] Of the 46,697.0 MW of additional capacity that cleared in RPM auctions for the 2007/2008 through 2022/2023 Delivery Years, 34,853.8 MW (74.6 percent) were based on market funding. Of the 3,794.3 MW of additional capacity that cleared in RPM auctions for the 2023/2024 through 2024/2025 Delivery Years, 3,557.4 MW (93.8 percent) were based on market funding. Those investments were made based on the assumption that markets would be allowed to work and that inefficient units would exit.

It is essential that any approach to the PJM markets incorporate a consistent view of how the preferred market design is expected to provide competitive results in a sustainable market design over the long run. A sustainable market design means a market design that results in appropriate incentives to competitive market participants to retire units and to invest in new units over time such that reliability is ensured as a result of the functioning of the market.

A sustainable competitive wholesale power market must recognize three salient structural elements: state nonmarket revenues for renewable energy; a significant level of generation resources subject to cost of service regulation; and the structure and performance of the existing market based generation fleet.

In order to attract and retain adequate resources for the reliable operation of the energy market, revenues from PJM energy, ancillary services and capacity markets must be adequate for those resources. That adequacy requires a capacity market. The capacity market plays the essential role of equilibrating the revenues necessary to incent competitive entry and exit of the resources needed for reliability, with the revenues from the energy market that are directly affected by nonmarket sources.

Price suppression below the competitive level in the capacity market should not be acceptable and is not consistent with a competitive market design. Harmonizing means that the integrity of each paradigm is maintained and respected. Harmonizing permits nonmarket resources to have an unlimited impact on energy markets and energy prices. Harmonizing means designing a capacity market to account for these energy market impacts, clearly limiting the impact of nonmarket revenues on the capacity market and ensuring competitive outcomes in the capacity market and thus in the entire market.

45 See "Analysis of the 2018/2019 RPM Base Residual Auction Revised," <http://www.monitoringanalytics.com/reports/Reports/2016/IMM_Analysis_of_the_20182019_RPM_Base_Residual_Auction_20160706.pdf> (July 6, 2016).

46 See "Analysis of the 2019/2020 RPM Base Residual Auction Revised," <http://www.monitoringanalytics.com/reports/Reports/2016/IMM_Analysis_of_the_20192020_RPM_BRA_20160831-Revised.pdf> (August 31, 2016).

47 See "Analysis of the 2020/2021 RPM Base Residual Auction," <http://www.monitoringanalytics.com/reports/Reports/2017/IMM_Analysis_of_the_20202021_RPM_BRA_20171117.pdf> (November 11, 2017).

48 See "Analysis of the 2021/2022 RPM Base Residual Auction - Revised," <http://www.monitoringanalytics.com/reports/Reports/2018/IMM_Analysis_of_the_20212022_RPM_BRA_Revised_20180824.pdf> (August 24, 2018).

49 See "Analysis of the 2022/2023 RPM Base Residual Auction," <https://www.monitoringanalytics.com/reports/Reports/2022/IMM_Analysis_of_the_20222023_RPM_BRA_20220222.pdf> (February 22, 2022).

50 See "Analysis of the 2023/2024 RPM Base Residual Auction," <https://www.monitoringanalytics.com/reports/Reports/2022/IMM_Analysis_of_the_20232024_RPM_Base_Residual_Auction_20221028.pdf> (October 28, 2022).

51 See "Analysis of Replacement Capacity for RPM Commitments: June 1, 2007 to June 1, 2017," <http://www.monitoringanalytics.com/reports/Reports/2017/IMM_Report_on_Capacity_Replacement_Activity_4_20171214.pdf> (December 14, 2017).

52 See "Analysis of Replacement Capacity for RPM Commitments: June 1, 2007 to June 1, 2019," <http://www.monitoringanalytics.com/reports/Reports/2019/IMM_Analysis_of_Replacement_Capacity_for_RPM_Commitments_June_1_2007_to_June_1_2019_20190913.pdf> (September 13, 2019).

53 See "Analysis of the 2023/2024 RPM Base Residual Auction Revised," <http://www.monitoringanalytics.com/reports/Reports/2022/IMM_Analysis_of_the_20232024_RPM_Base_Residual_Auction_20221028.pdf> (October 28, 2022).

54 The calculated reserve margin for June 1, 2023, does not account for cleared buy bids that have not been used in replacement capacity transactions.

55 "2020 PJM Generation Capacity and Funding Sources 2007/2008 through 2021/2022 Delivery Years," <http://www.monitoringanalytics.com/reports/Reports/2020/IMM_2020_PJM_Generation_Capacity_and_Funding_Sources_20072008_through_20212022_DY_20200915.pdf> (September 15, 2020).

Table 5-2 RPM related MMU reports: January 2022 through March 2023

Date	Name
January 5, 2022	MSOC Issues https://www.monitoringanalytics.com/reports/Presentations/2022/IMM_RASTF_MSOC_Issues_20220110.pdf
January 7, 2022	Reactive Power Compensation and the Capacity Market https://www.monitoringanalytics.com/reports/Presentations/2022/IMM_RPCTF_Reactive_Power_Compensation_20220107.pdf
January 27, 2022	Data Submission Window Reopening for the 2023/2024 RPM Base Residual Auction https://www.monitoringanalytics.com/reports/Market_Messages/RPM_Material/IMM_Data_Submission_Window_Reopening_2023-2024_Base_Residual_Auction_Updated_20220127.pdf
February 4, 2022	Data Submission Window Reopening for the 2023/2024 RPM Base Residual Auction - Updated https://www.monitoringanalytics.com/reports/Market_Messages/RPM_Material/IMM_Data_Submission_Window_Reopening_20232024_Base_Residual_Auction_Updated_20220204.pdf
February 11, 2022	2022 Quadrennial Review: IMM Proposals and Results https://www.monitoringanalytics.com/reports/Presentations/2022/IMM_Quadrennial_Review_IMM_CONE_CT_CC_Study_20220211.pdf
February 22, 2022	Analysis of the 2022/2023 RPM Base Residual Auction https://www.monitoringanalytics.com/reports/Reports/2022/IMM_Analysis_of_the_20222023_RPM_BRA_20220222.pdf
February 25, 2022	Generation Capacity Resources in PJM Region Subject to RPM Must Offer Obligation for 2022/2023 and 2023/2024 Delivery Years https://www.monitoringanalytics.com/reports/Market_Messages/RPM_Material/IMM_Notice_RPM_Must_Offer_Obligations_20220225.pdf
March 2, 2022	IMM Determinations Posted for the PJM 2023/2024 RPM Base Residual Auction https://www.monitoringanalytics.com/reports/Market_Messages/RPM_Material/IMM_Determinations_on_RPM_Requests_2023-2024_Base_Residual_Auction_Updated_20220302.pdf
March 7, 2022	IMM Determinations Posted for the PJM 2023/2024 RPM Base Residual Auction – Updated https://www.monitoringanalytics.com/reports/Market_Messages/RPM_Material/IMM_Determinations_on_RPM_Requests_2023-2024_Base_Residual_Auction_Updated_20220307.pdf
March 25, 2022	Quadrennial Review: VRR Curve https://www.monitoringanalytics.com/reports/Presentations/2022/IMM_Quadrennial_Review_VRR_Curve_20220325.pdf
March 25, 2022	Quadrennial Review: IMM Gross and Net CONE Update https://www.monitoringanalytics.com/reports/Presentations/2022/IMM_Quadrennial_Review_IMM_CONE_CT_CC_Proposals_and_Results_20220325.pdf
April 11, 2022	MSOC http://www.monitoringanalytics.com/reports/Presentations/2022/IMM_RASTF_MSOC_20220411.pdf
April 20, 2022	IMM Comments re MSOC Show Cause Order Docket No. EL22-22 http://www.monitoringanalytics.com/filings/2022/IMM_Comments_Docket_No_EL22-22_et_al_20220420.pdf
April 22, 2022	IMM CONE Study Update http://www.monitoringanalytics.com/reports/Presentations/2022/IMM_MIC_2022_Quad_Review_CONE_CT_CC_20220422.pdf
April 22, 2022	Impact of Brattle Proposed VRR Curves http://www.monitoringanalytics.com/reports/Presentations/2022/IMM_MIC_2022_Quad_Review_Impact_of_Brattle_Proposed_VRR_Curves_20220422.pdf
May 4, 2022	IMM RASTF MSOC Presentation http://www.monitoringanalytics.com/reports/Presentations/2022/IMM_RASTF_MSOC_20220504.pdf
May 23, 2022	IMM Brief of Intervenor for Petitioners re US Court of Appeals Third Circuit EPSA vs. FERC Docket Nos. 21-3205, et al http://www.monitoringanalytics.com/filings/2022/IMM_Brief_of_Intervenor_for_Petitioners_Docket_Nos_21-3205_et_al_20220523.pdf
May 26, 2022	Capacity Definition http://www.monitoringanalytics.com/reports/Presentations/2022/IMM_RASTF_Capacity_Definition_20220526.pdf
June 7, 2022	Generation Capacity Resources in PJM Region Subject to RPM Must Offer Obligation for 2023/2024 Delivery Year http://www.monitoringanalytics.com/reports/Market_Messages/RPM_Material/IMM_Notice_re_RPM_Must_Offer_Obligations_20220607.pdf
June 10, 2022	CPQR Simulation Approach http://www.monitoringanalytics.com/reports/Presentations/2022/IMM_RASTF_CPQR_Simulation_Approach_MSOC_20220610.pdf
June 21, 2022	Quadrennial Review Impact of VRR Shape Proposal http://www.monitoringanalytics.com/reports/Presentations/2022/IMM_Quad_Review_Impact_of_VRR_Shape_Proposal_20220621.pdf
June 23, 2022	IMM MSOC Package Executive Summary http://www.monitoringanalytics.com/reports/Presentations/2022/IMM_RASTF_MSOC_Package_Executive_Summary_20220620.pdf
July 8, 2022	Data Submission Window Opening for the 2024/2025 RPM Base Residual Auction http://www.monitoringanalytics.com/reports/Market_Messages/RPM_Material/IMM_Data_Submission_Window_Opening_20242025_Base_Residual_Auction_20220708.pdf
July 13, 2022	Impact of VRR Shape Proposals http://www.monitoringanalytics.com/reports/Presentations/2022/IMM_MIC_Impact_of_VRR_Shape_Proposals_20220713.pdf
August 24, 2022	Comparison of IMM Net CONE to PJM Net CONE http://www.monitoringanalytics.com/reports/Presentations/2022/IMM_Quadrennial_Review_Comparison_IMM_Net_CONE_to_PJM_Net_CONE_20220824.pdf
September 7, 2022	Market Approach to Behind the Generator Load http://www.monitoringanalytics.com/reports/Presentations/2022/IMM_MIC_Market_Approach_to_BGL_20220907.pdf
September 9, 2022	IMM Determinations Posted for the PJM 2024/2025 RPM Base Residual Auction http://www.monitoringanalytics.com/reports/Market_Messages/RPM_Material/IMM_Determinations_on_RPM_Requests_2024-2025_Base_Residual_Auction_20220908.pdf
September 28, 2022	Estimated Impact of Reactive Offset on Capacity Market Results http://www.monitoringanalytics.com/reports/Presentations/2022/IMM_RCPTF_Estimated_Impact_of_Reactive_Offset_on_Capacity_Market_Results_20220928.pdf
September 30, 2022	Generation Capacity Resources in PJM Region Subject to RPM Must Offer Obligation for 2023/2024 and 2024/2025 Delivery Years http://www.monitoringanalytics.com/reports/Market_Messages/RPM_Material/IMM_Notice_RPM_Must_Offer_Obligations_20220930.pdf
October 13, 2022	Market Approach to Behind the Generator Load (BGL) http://www.monitoringanalytics.com/reports/Presentations/2022/IMM_MIC_Market_Approach_to_BGL_20221013.pdf
October 28, 2022	Analysis of the 2023/2024 RPM Base Residual Auction http://www.monitoringanalytics.com/reports/Reports/2022/IMM_Analysis_of_the_20232024_RPM_Base_Residual_Auction_20221028.pdf
November 16, 2022	IMM Answer re 2022 PJM Quadrennial Review Docket No. ER22-2984 http://www.monitoringanalytics.com/filings/2022/IMM_Answer_Docket_No_ER22-2984_20221116.pdf
December 6, 2022	Generation Capacity Resources in PJM Region Subject to RPM Must Offer Obligation for 2023/2024 and 2024/2025 Delivery Years http://www.monitoringanalytics.com/reports/Market_Messages/RPM_Material/IMM_Notice_RPM_Must_Offer_Obligations_20221206.pdf

Table 5-2 RPM related MMU reports: January 2022 through March 2023 (continued)

Date	Name
December 8, 2022	Generation Capacity Resources in PJM Region Subject to RPM Must Offer Obligation for 2023/2024 and 2024/2025 Delivery Years-Revised http://www.monitoringanalytics.com/reports/Market_Messages/RPM_Material/IMM_Notice_RPM_Must_Offer_Obligations_20221208.pdf
December 21, 2022	IMM Determinations Posted for the PJM 2023/2024 RPM Third Incremental Auction http://www.monitoringanalytics.com/reports/Market_Messages/RPM_Material/IMM_Determinations_Posted_for_the_PJM_2023-2024_RPM_Third_Incremental_Auction_20221221.pdf
January 13, 2023	IMM Comments re ELCC/CIR Complaint Docket No. EL23-13 http://www.monitoringanalytics.com/filings/2023/IMM_Comments_Docket_No_EL23-13_20230113.pdf
January 13, 2023	Analysis of the 2022/2023 RPM Base Residual Auction - Revised http://www.monitoringanalytics.com/reports/Reports/2023/IMM_Analysis_of_the_20222023_RPM_BRA_Revised_20230113.pdf
January 13, 2023	Data Submission Window Opening for the 2025/2026 RPM Base Residual Auction http://www.monitoringanalytics.com/reports/Market_Messages/RPM_Material/IMM_Data_Submission_Window_Opening_2025-2026_Base_Residual_Auction_20230113.pdf
January 18, 2023	IMM Comments re Modernizing Electricity Market Design Docket No. AD21-10 http://www.monitoringanalytics.com/filings/2023/IMM_Comments_Docket_No_AD21-10_20230118.pdf
January 18, 2023	MMU Calculated Net Revenue Values for the 2025/2026 RPM Base Residual Auction http://www.monitoringanalytics.com/reports/Market_Messages/RPM_Material/IMM_Calculated_Net_Revenue_Values_20230118.pdf
January 20, 2023	IMM Comments re LDA Reliability Requirement Docket No. ER23-729 and EL23-19 http://www.monitoringanalytics.com/filings/2023/IMM_Comments_Docket_Nos_ER23-729_EL23-19_20230120.pdf
January 31, 2023	IMM Capacity Market Design Proposal http://www.monitoringanalytics.com/reports/Presentations/2023/IMM_RASTF_Capacity_Market_Design_Proposal_20230131.pdf
February 3, 2023	IMM Answer re LDA Reliability Requirement Docket No. EL23-19 and ER23-729 http://www.monitoringanalytics.com/filings/2023/IMM_Answer_Docket_No_EL23-19_ER23%E2%80%90729_20230203.pdf
February 10, 2023	High Level Capacity Market Design Proposal http://www.monitoringanalytics.com/reports/Presentations/2023/IMM_High_Level_Capacity_Market_Design_Proposal_20230210.pdf
February 16, 2023	IMM Answer re LDA Reliability Requirement Docket No. EL23-19 and ER23-729 http://www.monitoringanalytics.com/filings/2023/IMM_Answer_Docket_No_EL23-19_ER23-729_20230216.pdf
March 15, 2023	IMM Comments - Corrected re Maintenance Adder Costs Revisions Docket No. ER23-1138 http://www.monitoringanalytics.com/filings/2023/IMM_Comments_Corrected_Docket_No_ER23-1138_20230315.pdf
March 16, 2023	IMM Answer to Protests re Generation Capacity Resources CIRs in ELCC Docket No. ER23-1067 http://www.monitoringanalytics.com/filings/2023/IMM_Answer_to_Protest_Docket_No_ER23-1067_20230316.pdf
March 16, 2023	IMM Determinations Posted for the PJM 2025/2026 RPM Base Residual Auction http://www.monitoringanalytics.com/reports/Market_Messages/RPM_Material/IMM_Determinations_on_RPM_Requests_2025-2026_Base_Residual_Auction_20230316.pdf
March 20, 2023	Generation Capacity Resources in PJM Region Subject to RPM Must Offer Obligation for 2023/2024 and 2024/2025 Delivery Years http://www.monitoringanalytics.com/reports/Market_Messages/RPM_Material/IMM_Notice_RPM_Must_Offer_Obligations_20230320.pdf
April 20, 2023	Capacity Market Design Proposal http://www.monitoringanalytics.com/reports/Presentations/2023/IMM_CIFP_Capacity_Market_Design_Proposal_20230420.pdf

Installed Capacity

On January 1, 2023, RPM installed capacity was 183,388.8 MW (Table 5-3).[56] Over the next three months, new generation, unit deactivations, facility reratings, plus import and export shifts resulted in RPM installed capacity of 183,311.8 MW on March 31, 2023, a decrease of 77.0 MW or 0.0 percent from the January 1 level.[57] [58] The 77.0 MW decrease was the net result of derates (213.4 MW), and deactivations or changes in capacity resource status (8.0 MW), partially offset by new or reactivated generation (79.4 MW) and net capacity modifications (65.0 MW).

At the beginning of the new delivery year on June 1, 2022, RPM installed capacity was 180,903.7 MW, an increase of 2,411.0 MW or 1.3 percent from the May 31, 2022, level of 183,314.7 MW. This change occurs as a result of deactivations, derates, capacity modifications, and import/export contracts beginning and/or ending at the start of the new delivery year.

Table 5-3 Installed capacity (By fuel source): January 1, January 31, February 28, and March 31, 2023

	01-Jan-23		31-Jan-23		28-Feb-23		31-Mar-23	
	MW	Percent	MW	Percent	MW	Percent	MW	Percent
Coal	42,937.0	23.4%	42,937.0	23.4%	42,896.8	23.4%	42,896.8	23.4%
Gas	87,931.3	47.9%	87,931.3	47.9%	87,903.3	48.0%	87,968.3	48.0%
Hydroelectric	8,491.7	4.6%	8,491.7	4.6%	8,480.4	4.6%	8,480.4	4.6%
Nuclear	31,971.0	17.4%	31,971.0	17.4%	31,929.7	17.4%	31,852.1	17.4%
Oil	5,196.2	2.8%	5,196.2	2.8%	5,173.2	2.8%	5,173.2	2.8%
Solar	2,711.1	1.5%	2,756.7	1.5%	2,778.5	1.5%	2,790.5	1.5%
Solid waste	649.4	0.4%	649.4	0.4%	649.4	0.4%	649.4	0.4%
Wind	3,501.1	1.9%	3,501.1	1.9%	3,501.1	1.9%	3,501.1	1.9%
Total	183,388.8	100.0%	183,434.4	100.0%	183,312.4	100.0%	183,311.8	100.0%

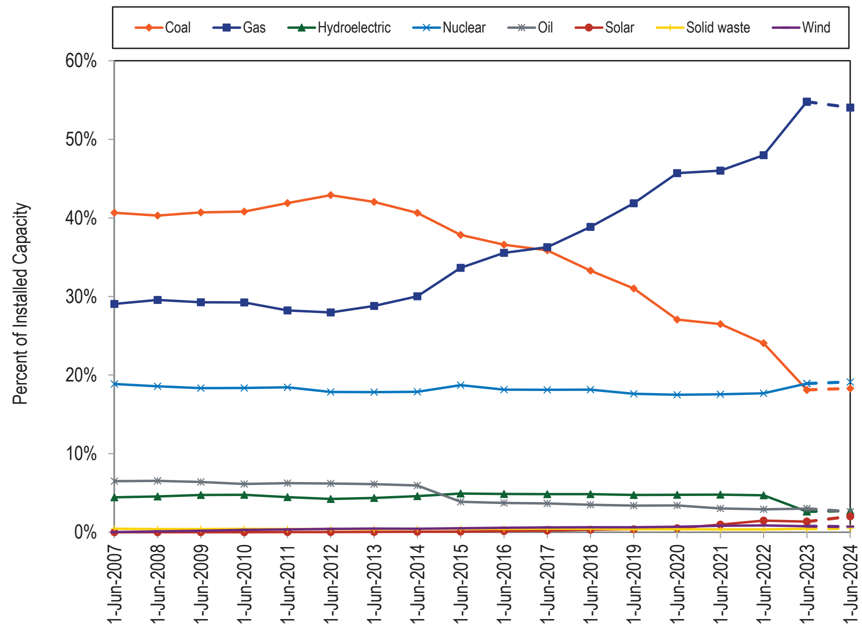
56 Percent values shown in Table 5-3 are based on unrounded, underlying data and may differ from calculations based on the rounded values in the tables.

57 Unless otherwise specified, the capacity described in this section is the summer installed capacity rating of all PJM generation capacity resources, as entered into the Capacity Exchange system, regardless of whether the capacity cleared in the RPM auctions.

58 Wind resources accounted for 3,501.1 MW, and solar resources accounted for 2,790.5 MW of installed capacity in PJM on March 31, 2023. PJM administratively reduces the capabilities of all wind generators to 14.7 percent for wind farms in mountainous terrain and 17.6 percent for wind farms in open terrain, and solar generators to 42.0 percent for ground mounted fixed panel, 60.0 percent for ground mounted tracking panel, and 38.0 percent for other than ground mounted solar arrays, of nameplate capacity when determining the installed capacity because wind and solar resources cannot be assumed to be available on peak and cannot respond to dispatch requests. As data become available, unforced capability of wind and solar resources will be calculated using actual data. There are additional wind and solar resources not reflected in total capacity because they are energy only resources and do not participate in the PJM Capacity Market. See "PJM Manual 21: Rules and Procedures for Determination of Generating Capability," Appendix B.3 Calculation Procedure, Rev. 16 (August 1, 2021). The derating approach will be replaced with ELCC starting in the 2023/2024 Delivery Year.

Figure 5-1 shows the share of installed capacity by fuel source for the first day of each delivery year, from June 1, 2007, to June 1, 2022, as well as the expected installed capacity for the 2023/2024 Delivery Year, based on the results of all auctions held through December 31, 2022.[59] On June 1, 2007, coal comprised 40.7 percent of the installed capacity, reached a maximum of 42.9 percent in 2012, decreased to 24.0 percent on June 1, 2022, and is projected to decrease to 16.7 percent by June 1, 2023. The share of gas increased from 29.1 percent on June 1, 2007, to 48.0 percent on June 1, 2022, and is projected to increase to 55.4 percent on June 1, 2023.

Figure 5-1 Percent of installed capacity (By fuel source): June 1, 2007 through June 1, 2024



59 Due to EFORd values not being finalized for future delivery years, the projected installed capacity is based on cleared unforced capacity (UCAP) MW using the EFORd submitted with the offer.

Table 5-4 shows the RPM installed capacity on January 1, 2023, through March 31, 2023, for the top five generation capacity resource owners, excluding FRR committed MW.

Table 5-4 Installed capacity by parent company: January 1, January 31, February 28, and March 31, 2023

	01-Jan-23			31-Jan-23			28-Feb-23			31-Mar-23		
Parent Company	ICAP (MW)	Percent of Total ICAP	Rank	ICAP (MW)	Percent of Total ICAP	Rank	ICAP (MW)	Percent of Total ICAP	Rank	ICAP (MW)	Percent of Total ICAP	Rank
Constellation Energy Generation, LLC	20,417.8	13.6%	1	20,417.8	13.6%	1	20,391.4	13.6%	1	20,391.4	13.6%	1
ArcLight Capital Partners, LLC	14,230.1	9.5%	2	14,230.1	9.5%	2	13,394.7	8.9%	2	13,394.7	8.9%	2
LS Power Group	10,803.4	7.2%	3	10,803.4	7.2%	3	11,638.7	7.7%	3	11,638.7	7.7%	3
Riverstone Holdings LLC	10,370.4	6.9%	4	10,370.4	6.9%	4	10,329.2	6.9%	4	10,251.6	6.8%	4
Vistra Energy Corp.	8,671.5	5.8%	5	8,671.5	5.8%	5	8,668.5	5.8%	5	8,668.5	5.8%	5

The sources of funding for generation owners can be categorized as one of two types: market and nonmarket. Market funding is from private investors bearing the investment risk without guarantees or support from any public sources, subsidies or guaranteed payment by ratepayers. Providers of market funding rely entirely on market revenues. Nonmarket funding is from guaranteed revenues, including cost of service rates for a regulated utility and subsidies. Table 5-5 shows the RPM installed capacity on January 1, 2023, to March 31, 2023, by funding type.

Table 5-5 Installed capacity by funding type: January 1, January 31, February 28, and March 31, 2023

	01-Jan-23		31-Jan-23		28-Feb-23		31-Mar-23	
Funding Type	ICAP (MW)	Percent of Total ICAP	ICAP (MW)	Percent of Total ICAP	ICAP (MW)	Percent of Total ICAP	ICAP (MW)	Percent of Total ICAP
Market	135,714.9	74.0%	135,714.9	74.0%	135,626.2	74.0%	135,625.6	74.0%
Nonmarket	47,673.9	26.0%	47,719.5	26.0%	47,686.2	26.0%	47,686.2	26.0%
Total	183,388.8	100.0%	183,434.4	100.0%	183,312.4	100.0%	183,311.8	100.0%

Fuel Diversity

Figure 5-2 shows the fuel diversity index (FDI_c) for RPM installed capacity.[60] The FDI_c is defined as $1-\sum_{i=1}^{N} s_i^2$, where s_i is the percent share of fuel type *i*. The minimum possible value for the FDI_c is zero, corresponding to all capacity from a single fuel type. The maximum possible value for the FDI_c is achieved when each fuel type has an equal share of capacity. For a capacity mix of eight fuel types, the maximum achievable index is 0.875. For all FDI calculations prior to June 1, 2023, the fuel type categories used in the calculation of the FDI_c are the eight fuel sources in Table 5-3. Two additional fuel types, batteries and hybrid solar, are included beginning in June 2023. The maximum achievable index with ten fuel types is 0.9. The FDI_c is stable and does not exhibit any long-term trends. The only significant deviation occurred with the expansion of the PJM footprint. On April 1, 2002, PJM expanded with the addition of Allegheny Power System, which added about 12,000 MW of generation.[61] The reduction in the FDI_c resulted from an increase in coal capacity resources. A similar but more significant reduction occurred in 2004 with the expansion into the COMED, AEP, and DAY Control Zones.[62] The average FDI_c for the first three months of

60 The MMU developed the FDI to provide an objective metric of fuel diversity. The FDI metric is similar to the HHI used to measure market concentration. The FDI is calculated separately for energy output and for installed capacity. The FDI_c includes derated capacity values for intermittent capacity subject to derating.

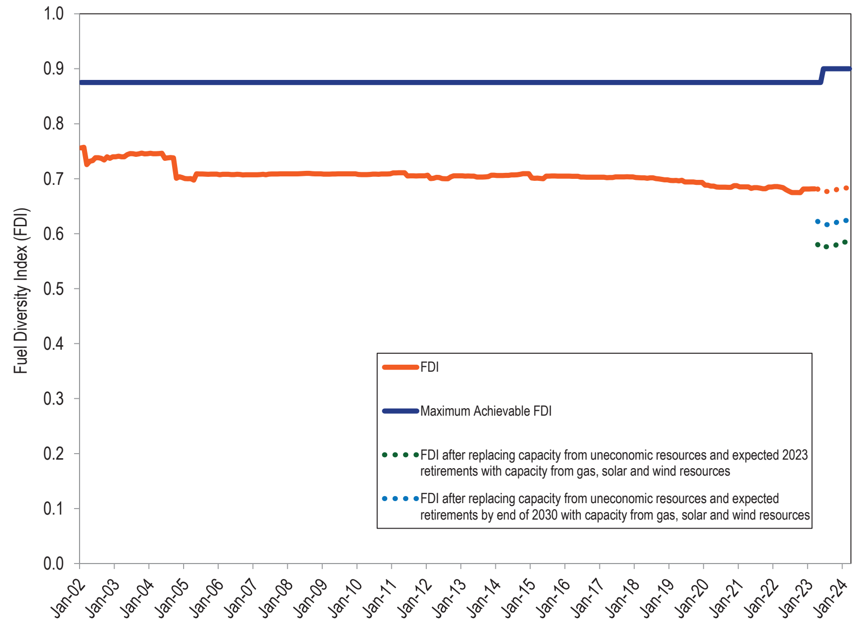
61 On April 1, 2002, the PJM Region expanded with the addition of Allegheny Power System under a set of agreements known as "PJM-West." See page 4 in the *2002 State of the Market Report for PJM* for additional details.

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

2023 decreased 0.6 percent compared to the first three months of 2023. Figure 5-2 also includes the expected FDI_c through March 2024 based on cleared RPM auctions. The expected FDI_c is indicated in Figure 5-2 by the dotted orange line.

The FDI_c was used to measure the impact on fuel diversity of potential retirements of resources that the MMU has identified as being at risk of retirement. A total of 8,963 MW of capacity are at risk of retirement, consisting of 6,086 MW currently planning to retire in 2023 and 2,877 MW expected to retire by the end of 2023 for regulatory reasons. This capacity consists primarily of coal and gas peaker units.[63] The dotted green line in Figure 5-2 shows the FDI_c assuming that the capacity from the expected 2023 retirements were replaced by gas, wind and solar capacity.[64] The FDI_c under these assumptions would have been 14.7 percent lower than the actual FDI_c. A total of 51,757 MW of capacity are at risk of retirement by the end of 2030, consisting of 6,628 MW currently planning to retire, 23,509 MW expected to retire for regulatory reasons, and 21,621 MW expected to be uneconomic.[65] Replacing this capacity with gas, wind and solar capacity results in a counterfactual [66] FDI_c that is 8.8 percent lower than the actual FDI_c.

Figure 5-2 Fuel Diversity Index for installed capacity: January 1, 2002 through March 1, 2024



63 See the *2022 State of the Market Report for PJM*, Section 7: Net Revenue
64 It is assumed that 2,149.8 MW of replacement capacity is from solar units and 205.0 MW from wind units, with the remaining replacement capacity coming from gas units. This is the amount of derated wind and solar capacity needed to produce 2,694.9 GWh of generation in the months January through March assuming the average capacity derate factors in the Planned Generation Additions subsection of Section 12 and the average capacity factors for wind and solar capacity resources in Table 8-33 and Table 8-36. This level of GWh represents the increase in renewable generation required by RPS in the first three months of 2024 over the level of renewable generation that was required by RPS in the first three months of 2023. The split between solar and wind is based on queue data.
65 See Table 7-52 in the *2022 State of the Market Report for PJM*, Section 7: Net Revenue
66 For the second scenario, 13,006.7 MW of replacement capacity is from solar units and 1,243.1 MW from wind units, with the remaining replacement capacity coming from gas units. This is sufficient capacity, assuming the average capacity derate factors in the Planned Generation Additions subsection of Section 12 and capacity factors in Table 8-33 and Table 8-36, to cover the increase in RPS requirement of 16,304.4 MWh in the first three months of 2030 over 2023 RPS requirements.

RPM Capacity Market

The RPM Capacity Market, implemented June 1, 2007, is a forward looking, annual, locational market, with a must offer requirement for existing generation capacity resources, except for intermittent and storage resources including hydro, and except for resources owned by entities that elect the fixed resource requirement (FRR) option, and mandatory participation by load, with performance incentives, that includes clear market power mitigation rules and that permits the direct participation of demand-side resources.

Annual base auctions are held in May for delivery years that are three years in the future. Effective January 31, 2010, First, Second, and Third Incremental Auctions are conducted 20, 10, and three months prior to the delivery year.[67] In the first three months of 2023, the 2023/2024 RPM Third Incremental Auction was conducted. The 2024/2025 RPM Base Residual Auction was conducted in 2022, but the results were not posted until February 27, 2023, due to an issue with the DPL South reliability requirement.

Market Structure

Supply

Table 5-6 shows generation capacity changes since the implementation of the Reliability Pricing Model through the 2021/2022 Delivery Year. The 19,655.3 MW increase was the result of new generation capacity resources (37,326.8 MW), reactivated generation capacity resources (1,380.4 MW), uprates (7,989.8 MW), integration of external zones (21,967.5 MW), a net decrease in capacity exports (950.7 MW), offset by a net decrease in capacity imports (1,013.0 MW), deactivations (45,169.6 MW) and derates (3,777.3 MW).

Table 5-7 shows the calculated RPM reserve margin and reserve in excess of the defined installed reserve margin (IRM) for June 1, 2019, through June 1, 2024, and accounts for cleared capacity, replacement capacity, and deficiency MW for all auctions held and the most recent peak load forecast for each delivery year. The completion of the replacement process using cleared buy bids from RPM incremental auctions includes two transactions. The first step is for the entity to submit and clear a buy bid in an RPM incremental auction. The next step is for the entity to complete a separate replacement transaction using the cleared buy bid capacity. Without an approved early replacement transaction requested for defined physical reasons, replacement capacity transactions can be completed only after the EFORds for the delivery year are finalized, on November 30 in the year prior to the delivery year, but before the start of the delivery day. The calculated reserve margins for June 1, 2023, and June 1, 2024, do not account for cleared buy bids that have not been used in replacement capacity transactions.

Future Changes in Generation Capacity[68]

As shown in Table 5-6, for the period from the introduction of the RPM capacity market design in the 2007/2008 Delivery Year through the 2021/2022 Delivery Year, internal installed capacity decreased by 2,249.9 MW after accounting for new capacity resources, reactivations, and uprates (46,697.0 MW) and capacity deactivations and derates (48,946.9 MW).

For the current and future delivery years (2022/2023 through 2024/2025), new generation capacity is defined as capacity that cleared an RPM auction for the first time for the specified delivery year. Based on expected completion rates of cleared new generation capacity (3,338.2 MW) and pending deactivations (6,304.6 MW), PJM capacity is expected to decrease by 2,966.4 MW for the 2022/2023 through 2024/2025 Delivery Years.

67 See Letter Order, Docket No. ER10-366-000 (January 22, 2010).

68 For more details on future changes in generation capacity, see "2020 PJM Generation Capacity and Funding Sources 2007/2008 through 2021/2022 Delivery Years," <http://www.monitoringanalytics.com/reports/Reports/2020/IMM_2020_PJM_Generation_Capacity_and_Funding_Sources_20072008_through_20212022_DY_20200915.pdf> (September 15, 2020).

Table 5-6 Generation capacity changes: 2007/2008 through 2021/2022[69]

	ICAP (MW)								
	New	Reactivations	Uprates	Integration	Net Change in Capacity Imports	Net Change in Capacity Exports	Deactivations	Derates	Net Change
2007/2008	45.0	0.0	691.5	0.0	70.0	15.3	380.0	417.0	(5.8)
2008/2009	815.4	238.3	987.0	0.0	473.0	(9.9)	609.5	421.0	1,493.1
2009/2010	406.5	0.0	789.0	0.0	229.0	(1,402.2)	108.4	464.3	2,254.0
2010/2011	153.4	13.0	339.6	0.0	137.0	367.7	840.6	223.5	(788.8)
2011/2012	3,096.4	354.5	507.9	16,889.5	(1,183.3)	(1,690.3)	2,542.0	176.2	18,637.1
2012/2013	1,784.6	34.0	528.1	47.0	342.4	84.0	5,536.0	317.8	(3,201.7)
2013/2014	198.4	58.0	372.8	2,746.0	934.3	28.9	2,786.9	288.3	1,205.4
2014/2015	2,276.8	20.7	530.2	0.0	2,335.7	177.3	4,915.6	360.3	(289.8)
2015/2016	4,291.8	90.0	449.0	0.0	511.4	(117.8)	8,338.2	215.8	(3,094.0)
2016/2017	3,679.3	532.0	419.2	0.0	575.6	722.9	659.4	206.7	3,617.1
2017/2018	4,127.3	5.0	562.1	0.0	(1,025.1)	(695.1)	2,657.4	148.5	1,558.5
2018/2019	8,127.5	4.0	330.9	2,120.0	(3,217.0)	212.7	6,730.0	89.2	333.5
2019/2020	4,612.0	13.3	494.9	165.0	(1,196.6)	401.3	3,296.0	116.8	274.5
2020/2021	403.1	11.6	575.4	0.0	(37.9)	(111.6)	3,572.0	206.4	(2,714.6)
2021/2022	3,309.3	6.0	412.2	0.0	38.5	1,066.1	2,197.6	125.5	376.8
Total	37,326.8	1,380.4	7,989.8	21,967.5	(1,013.0)	(950.7)	45,169.6	3,777.3	19,655.3

As shown in Table 5-7, total reserves on June 1, 2024, will be 24,966.4 MW, of which 8,086.8 MW are in excess of the required level of reserves, which is 16,879.6 MW. In the 2024/2025 BRA, 18,133.0 MW were considered categorically exempt from the must offer requirement based on intermittent and capacity storage classification. Some of these resources were offered as capacity in the BRA and as part of FRR plans. The result was that 5,772.3 MW of intermittent and storage resources (31.8 percent of the exempt MW and 3.9 percent of total cleared MW) were not offered in the 2024/2025 BRA.

In the 2024/2025 BRA, the sum of cleared MW that were considered categorically exempt from the must offer requirement is 8,319.3 MW, or 49.3 percent of the required reserves and 33.3 percent of total reserves. The cleared MW of DR is 8,083.9 MW, or 47.9 percent of required reserves and 32.4 percent of total reserves. The sum of cleared MW that were categorically exempt from the must offer requirement and the cleared MW of DR is 16,403.2 MW, or 97.2 percent of required reserves and 65.7 percent of total reserves.

These results suggest that the required reserve margin and the actual reserve margin be considered carefully along with the obligations of the resources that the reserve margin assumes will be available.

69 The capacity changes in this report are calculated based on June 1 through May 31.

Table 5-7 RPM reserve margin: June 1, 2019, to June 1, 2024[70 71]

	01-Jun-19	01-Jun-20	01-Jun-21	01-Jun-22	01-Jun-23	01-Jun-24	
Forecast peak load ICAP (MW)	151,643.5	148,355.3	149,482.9	149,263.6	149,382.2	150,640.3	A
FRR peak load ICAP (MW)	12,284.2	11,488.3	11,717.7	28,292.8	29,554.6	29,421.6	B
PRD ICAP (MW)	0.0	558.0	510.0	230.0	235.0	305.0	C
Installed reserve margin (IRM)	16.0%	15.5%	14.7%	14.9%	14.9%	14.7%	D
Pool wide average EFORd	6.08%	5.78%	5.22%	5.08%	4.87%	5.02%	E
Forecast pool requirement (FPR)	1.090	1.088	1.087	1.091	1.093	1.089	F=(1+D)*(1-E)
RPM committed less deficiency UCAP (MW) (generation and DR)	162,276.1	159,560.4	156,633.6	137,944.8	141,227.5	139,810.2	G
RPM committed less deficiency ICAP (MW) (generation and DR)	172,781.2	169,348.8	165,260.2	145,327.4	148,457.4	147,199.6	H=G/(1-E)
RPM peak load ICAP (MW)	139,359.3	136,309.0	137,255.2	120,740.8	119,592.6	120,913.7	J=A-B-C
Reserve margin ICAP (MW)	33,421.9	33,039.8	28,005.0	24,586.6	28,864.8	26,285.9	K=H-J
Reserve margin (%)	24.0%	24.2%	20.4%	20.4%	24.1%	21.7%	L=K/J
Reserve margin in excess of IRM ICAP (MW)	11,124.4	11,911.9	7,828.5	6,596.3	11,045.5	8,511.6	M=K-D*J
Reserve margin in excess of IRM (%)	8.0%	8.7%	5.7%	5.5%	9.2%	7.0%	N=M/J
RPM peak load UCAP (MW)	130,886.3	128,430.3	130,090.5	114,607.2	113,768.4	114,843.8	P=J*(1-E)
RPM reliability requirement UCAP (MW)	151,832.0	148,331.5	149,210.1	131,679.9	130,714.7	131,723.4	Q=J*F
Reserve margin UCAP (MW)	31,389.8	31,130.1	26,543.1	23,337.6	27,459.1	24,966.4	R=G-P
Reserve cleared in excess of IRM UCAP (MW)	10,444.1	11,228.9	7,423.5	6,264.9	10,512.8	8,086.8	S=G-Q
Projected replacement capacity UCAP (MW)	0.0	0.0	0.0	0.0	2,469.7	0.0	T
Projected reserve margin	24.0%	24.2%	20.4%	20.4%	22.0%	21.7%	U=(H-T/(1-E))/J-1

Sources of Funding[72]

Developers use a variety of sources to fund their projects, including Power Purchase Agreements (PPA), cost of service rates, and private funds (from internal sources or private lenders and investors). PPAs can be used for a variety of purposes and the use of a PPA does not imply a specific source of funding.

New and reactivated generation capacity from the 2007/2008 Delivery Year through the 2022/2023 Delivery Year totaled 38,707.2 MW (82.9 percent of all additions), with 29,276.2 MW from market funding and 9,431.0 MW from nonmarket funding. Uprates to existing generation capacity from the 2007/2008 Delivery Year through the 2022/2023 Delivery Year totaled 7,989.8 MW (17.1 percent of all additions), with 5,577.6 MW from market funding and 2,412.2 MW from nonmarket funding. In summary, of the 46,697.0 MW of additional capacity from new, reactivated, and uprated generation that cleared in RPM auctions for the 2007/2008 through 2022/2023 Delivery Years, 34,853.8 MW (74.6 percent) were based on market funding.

Of the 3,794.3 MW of the additional generation capacity (new resources, reactivated resources, and uprates) that cleared in RPM auctions for the 2023/2024 Delivery Year through the 2024/2025 Deliver Year, 1,409.1 MW are not yet in service. Of those 1,409.1 MW that have not yet gone into service, 1,244.1 MW have market funding and 165.0 MW have nonmarket funding. Applying the historical completion rates, 67.6 percent of all the projects in development are expected to go into service (841.4 MW of the 1,244.1 MW of in development market funded projects; 111.6 MW of the 165.0 MW of in development nonmarket funded projects). Together, 953.0 MW of the 1,409.1 MW of new generation capacity that cleared MW in RPM and are not yet in service are expected to go into service in the 2023/2024 through 2024/2025 Delivery Years.

70 The calculated reserve margins in this table do not include EE on the supply side or the EE addback on the demand side. The EE excluded from the supply side for this calculation includes annual EE and summer EE. This is how PJM calculates the reserve margin.

71 These reserve margin calculations do not consider Fixed Resource Requirement (FRR) load.

72 For more details on sources of funding for generation capacity, see "2020 PJM Generation Capacity and Funding Sources 2007/2008 through 2021/2022 Delivery Years," <http://www.monitoringanalytics.com/reports/Reports/2020/IMM_2020_PJM_Generation_Capacity_and_Funding_Sources_20072008_through_20212022_DY_20200915.pdf> (September 15, 2020).

Of the 2,385.2 MW of the additional generation capacity that cleared in RPM auctions for the 2023/2024 through 2024/2025 Delivery Years and are already in service, 2,313.3 MW (97.0 percent) are based on market funding and 71.9 MW (3.0 percent) are based on nonmarket funding. In summary, 3,557.4 MW (93.8 percent) of the additional generation capacity (1,244.1 MW not yet in service and 2,313.3 MW in service) that cleared in RPM auctions for the 2023/2024 through 2024/2025 Delivery Years are based on market funding. Capacity additions based on nonmarket funding are 236.9 MW (6.2 percent) of proposed generation that cleared the RPM auctions for the 2023/2024 through 2024/2025 Delivery Years.

Demand

The MMU analyzed market sectors in the PJM Capacity Market to determine how they met their load obligations. The PJM Capacity Market was divided into the following sectors:

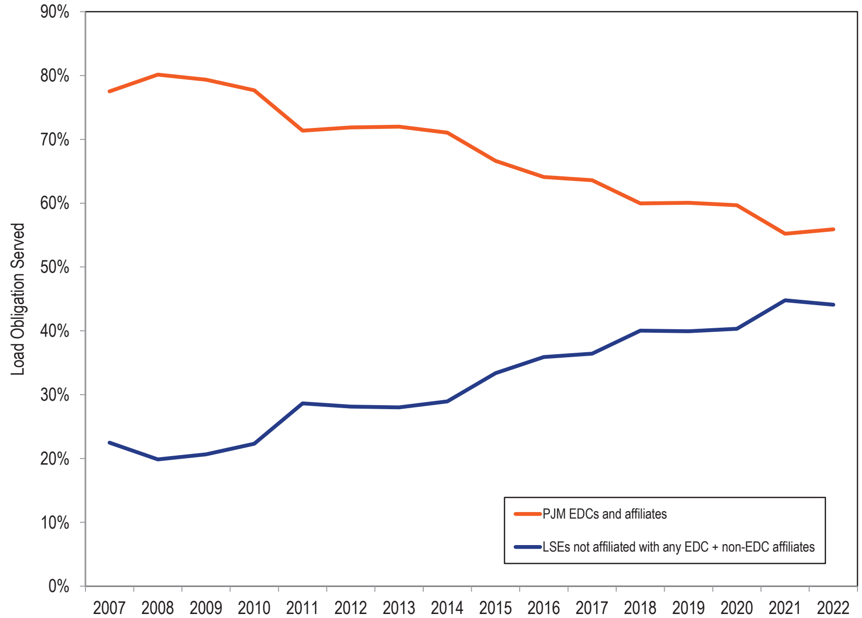
- **PJM EDC.** EDCs with a franchise service territory within the PJM footprint. This sector includes traditional utilities, electric cooperatives, municipalities and power agencies.
- **PJM EDC Generating Affiliate.** Affiliate companies of PJM EDCs that own generating resources.
- **PJM EDC Marketing Affiliate.** Affiliate companies of PJM EDCs that sell power and have load obligations in PJM, but do not own generating resources.
- **Non-PJM EDC.** EDCs with franchise service territories outside the PJM footprint.
- **Non-PJM EDC Generating Affiliate.** Affiliate companies of non-PJM EDCs that own generating resources.
- **Non-PJM EDC Marketing Affiliate.** Affiliate companies of non-PJM EDCs that sell power and have load obligations in PJM, but do not own generating resources.
- **Non-EDC Generating Affiliate.** Affiliate companies of non-EDCs that own generating resources.
- **Non-EDC Marketing Affiliate.** Affiliate companies of non-EDCs that sell power and have load obligations in PJM, but do not own generating resources.

On June 1, 2022, PJM EDCs and their affiliates maintained a large market share of load obligations under RPM, together totaling 55.9 percent (Table 5-8), up from 55.2 percent on June 1, 2021. The combined market share of LSEs not affiliated with any EDC and of non-PJM EDC affiliates was 44.1 percent, down from 44.8 percent on June 1, 2021. The share of capacity market load obligation fulfilled by PJM EDCs and their affiliates, and LSEs not affiliated with any EDC and non-PJM EDC affiliates from June 1, 2007, to June 1, 2022, is shown in Figure 5-3. PJM EDCs' and their affiliates' share of load obligation has decreased from 77.5 percent on June 1, 2007, to 55.9 percent on June 1, 2022. The share of load obligation held by LSEs not affiliated with any EDC and non-PJM EDC affiliates increased from 22.5 percent on June 1, 2007, to 44.1 percent on June 1, 2022. Prior to the 2012/2013 Delivery Year, obligation was defined as cleared and make whole MW in the Base Residual Auction and the Second Incremental Auction plus ILR forecast obligations. Effective with the 2012/2013 Delivery Year, obligation is defined as the sum of the unforced capacity obligations satisfied through all RPM auctions for the delivery year.

Table 5-8 Capacity market load obligation served: June 1, 2021 and June 1, 2022

	01-Jun-21		01-Jun-22		Change	
	Obligation (MW)	Percent of total obligation	Obligation (MW)	Percent of total obligation	Obligation (MW)	Percent of total obligation
PJM EDCs and Affiliates	96,306.4	55.2%	100,803.7	55.9%	4,497.4	0.7%
LSEs not affiliated with any EDC + non EDC Affiliates	78,114.1	44.8%	79,537.6	44.1%	1,423.6	(0.7%)
Total	174,420.4	100.0%	180,341.3	100.0%	5,920.9	0.0%

Figure 5-3 Capacity market load obligation served: June 1, 2007 through June 1, 2022



Capacity Transfer Rights (CTRs)

Capacity Transfer Rights (CTRs) are used to return capacity market congestion revenues to load. Load pays congestion. Capacity market congestion revenues are the difference between the total dollars paid by load for capacity and the total dollars received by capacity market sellers. The MW of CTRs available for allocation to LSEs in an LDA are equal to the Unforced Capacity imported into the LDA, less any MW of CETL paid for directly by market participants in the form of Qualifying Transmission Upgrades (QTUs) cleared in an RPM Auction, and Incremental Capacity Transfer Rights (ICTRs). There are two types of ICTRs, those allocated to a New Service Customer obligated to fund a transmission facility or upgrade and those associated with Incremental Rights-Eligible Required Transmission Enhancements.

The total required capacity in an LDA is provided by a mix of internal capacity and imported capacity. The imported capacity equals the total required capacity minus the internal capacity. The value of CTRs is based on the fact that load in an LDA pays the clearing price for all cleared capacity but that generators who provide imported capacity are paid a lower price based on the LDA in which they are located. The value of CTRs equals the imported MW times the price difference. This excess is paid by load and is returned to load using CTRs. CTRs are intended to permit customers to receive the benefit of importing cheaper capacity using transmission capability.

But PJM does not use the actual MW cleared in the BRA and three incremental auctions, the actual internal MW and the actual imported MW, when defining what customers pay and when defining the value of CTRs. Under the current rules, PJM defines the total MW needed for reliability in an LDA when clearing the BRA based on forecast demand at the time of the BRA. But PJM actually charges customers for the total MW needed for reliability based on forecast demand three years later, prior to the actual delivery year, and applies a zonal allocation. PJM also defines the internal capacity as the internal capacity after the final incremental auction conducted three years after the BRA, when auctions follow the traditional schedule. The difference between the updated MW needed for reliability and the updated internal capacity is the updated imported MW, adjusted for the final zonal allocation. In cases where the updated imported MW are smaller than the imported MW from the actual auction clearing, the total value of CTRs is lower that it would be if the actual auction clearing MW were used.

The actual load charges are allocated to each zone based on the ratio of the zonal forecast peak load to the RTO forecast peak load used for the third incremental auction conducted six months prior to the delivery year.

The CTR issue implies a broader issue with capacity market clearing and settlements. The capacity market is cleared based on a three year ahead forecast of load and offers of capacity. Payments to capacity resources in the delivery year are based on the capacity market clearing prices and quantities. But payments by customers in the delivery year are not based on market clearing prices and quantities. Payments by customers in each zone are based on the ratio of zonal forecast peak load to the RTO forecast peak load used for the Third Incremental Auction, run six months prior to the delivery year when auctions follow the traditional schedule.[73] The allocation sometimes creates significant differences between the capacity cleared to meet the reliability requirement and the capacity obligation allocated to the customers in a zone. For example, ComEd Zone, which is identical to ComEd LDA cleared 27,932.1 MW including 5,574.0 MW of imports in the 2021/2022 RPM BRA. The ComEd Zone's capacity obligation, immediately after the clearing of the Base Residual Auction was 24,983.0 MW. The final ComEd Zone's capacity obligation for the 2021/2022 Delivery Year after the Third Incremental Auction was 22,721.2 MW.

As with CTRs, the underlying reasons for not using the market clearing results are not clear. Although not stated explicitly, the goal appears to be to reflect the fact that actual loads change between the auction and the delivery year. But the simple reallocation of capacity obligations based on changes in the load forecast does not reflect the BRA market results. The MMU recommends that the market clearing results be used in settlements rather than the reallocation process currently used or that the process of modifying the obligations to pay for capacity be reviewed.

For LDAs in which the RPM auctions for a delivery year resulted in a positive average weighted Locational Price Adder, an LSE with CTRs corresponding to the LDA is entitled to a payment or charge equal to the Locational Price Adder multiplied by the MW of the LSEs' CTRs. The definition of the MW does not reflect auction clearing MW.

In the 2024/2025 RPM Base Residual Auction, BGE had 4,513.2 MW of CTRs with a total value of $38,728,614 and DPL had 544.7 MW with a total value of $1,085,516 and -253.2 MW of CTRs with a total value of -$964,981. EMAAC, excluding DPL, had 3,704.1 MW of CTRs with a total value of $7,381,909 and DEOK had 3,015.4 MW of CTRs with a total value of $74,093,944.

MAAC had 1,026.2 MW of customer funded ICTRs with a total value of $7,704,472, EMAAC had 40.0 MW of customer funded ICTRs with a total value of $79,716, BGE had 65.7 MW of customer funded ICTRs with a total value of $563,782 and DEOK had 155.0 MW of customer funded ICTRs with a total value of $3,808,629.

MAAC had 486.4 MW of ICTRs due to Incremental Rights-Eligible Required Transmission Enhancements with a value of $3,651,831, EMAAC had 948.0 MW of ICTRs due to Incremental Rights-Eligible Required Transmission Enhancements with a value of $1,889,269 and BGE had 306.0 MW with a value of $2,625,832.

Demand Curve

A central feature of PJM's Reliability Pricing Model (RPM) design is that the demand curve, or Variable Resource Requirement (VRR) curve, has a downward sloping segment. In the RPM market design, the supply of three year forward capacity is cleared against this VRR curve. A VRR curve is defined for each Locational Deliverability Area (LDA). This shape replaced the vertical demand curve at the reliability requirement. The downward sloping segment begins at the MW level that is approximately 1.0 percent less than the reliability requirement.[74] Figure 5-4 shows the shape of the VRR curve compared to a vertical demand curve at the reliability requirement for the 2024/2025 RPM Base Residual Auction.

In proposing the downward sloping portion of the VRR curve, PJM asserted that the sloping VRR curve recognizes the value of incremental capacity above the target reserve margin providing additional reliability benefit at a declining rate.[75]

The initial VRR curve, introduced in 2007, had a maximum price equal to 1.5 times the Net Cost of New Entry (Net CONE), determined annually based on fixed cost of new generating capacity or Gross Cost of New Entry (Gross CONE), net of the three year average energy and ancillary service revenues. That VRR curve was structured to yield auction clearing prices equal to the 1.5 times Net CONE when the amount of capacity cleared was less than 99 percent

73 See "PJM Manual 18: PJM Capacity Market," § 7.2.3 Final Zonal Unforced Capacity Obligations, Rev. 55 (Feb. 9, 2023).

74 The formula for the MW level where the VRR curve begins the downward slope is given by *(Reliability Requirement) x [1 – 1.2% / (Installed Reserve Margin)]*.

75 See 117 FERC ¶ 61,331 (2006).

of the target reserve margin and below 1.5 times Net CONE when the amount of capacity cleared was greater than 99 percent of the target reserve margin.

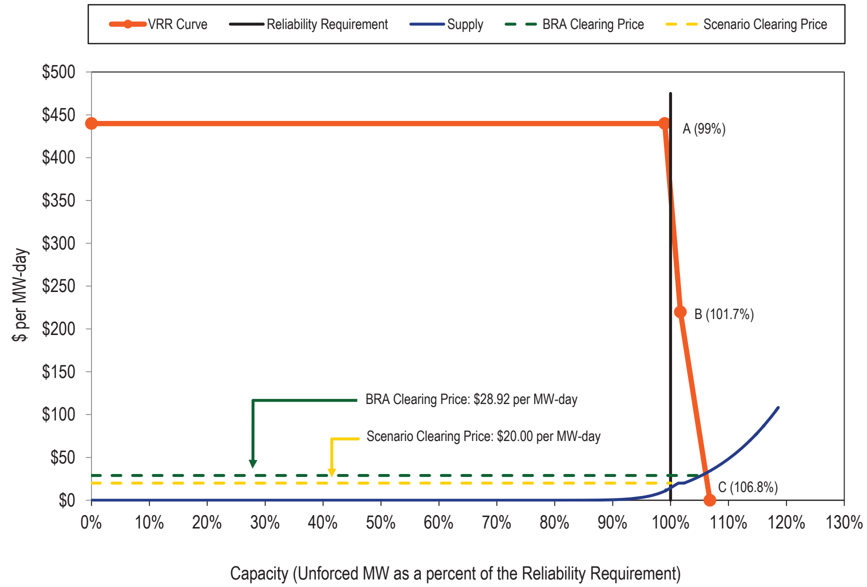
Effective for the 2018/2019 and subsequent delivery years, PJM revised the VRR curve.[76] PJM defines the reliability requirement as the capacity needed to satisfy the one event in ten years loss of load expectation (LOLE) for the RTO and capacity needed to satisfy the one event in 25 years loss of load expectation for the each LDA. The maximum price on the VRR curve is the greater of Gross CONE or 1.5 times Net CONE for all unforced capacity MW between 0 and 99 percent of the reliability requirement. The first downward sloping segment is from 99 percent and 101.7 percent of the reliability requirement. The second downward sloping segment is from 101.7 percent and 106.8 percent of the reliability requirement (Figure 5-4).

The downward sloping shape of the demand curve, the VRR curve, had a significant impact on the outcome of the 2023/2024 BRA. As a result of the downward sloping VRR demand curve, more capacity cleared in the market than would have cleared with a vertical demand curve set equal to the reliability requirement.

Based on actual auction clearing prices and quantities and uplift MW, total RPM market revenues for the 2024/2025 RPM Base Residual Auction were $2,198,835,999. If PJM had used a vertical demand curve set equal to the reliability requirement for 2024/2025 RPM Base Residual Auction and everything else had remained the same, total RPM market revenues for the 2024/2025 RPM Base Residual Auction would have been $1,381,442,645, a decrease of $817,393,354, or 37.2 percent, compared to the actual results. From another perspective, clearing the auction using a downward sloping VRR curve resulted in a 59.2 percent increase in RPM revenues for the 2024/2025 RPM Base Residual Auction compared to what RPM revenues would have been with a vertical demand curve set equal to the reliability requirement.

The PJM definition of the VRR curve means the clearing price and cleared quantity will be higher, almost without exception, using the current VRR curve than using a vertical demand curve at the reliability requirement. As a result, payments for capacity will be higher. Figure 5-4 shows the RTO VRR curve and RTO reliability requirement for the 2024/2025 RPM BRA. The clearing price and cleared quantity would have been lower if a vertical VRR curve set at the reliability requirement had been used in place of the existing VRR curve. In the 2024/2025 BRA, the RTO clearing price would have decreased from $28.92 per MW-day to $20.00 per MW-day, and the clearing quantity would have decreased from 147,478.9 MW to 139,121.6 MW.

Figure 5-4 Shape of the VRR curve relative to the reliability requirement: 2024/2025 Delivery Year



Market Concentration

Auction Market Structure

As shown in Table 5-9, in the 2024/2025 RPM Base Residual Auction all participants in the total PJM market as well as the LDA RPM markets failed the three pivotal supplier (TPS) test.[77] In the 2023/2024 RPM Third Incremental

76 "Third Triennial Review of PJM's Variable Resource Requirement Curve," The Brattle Group, May 15, 2014, <http://www.pjm.com//media/library/reports-notices/reliability-pricing-model/20140515-brattle-2014-pjm-vrr-curvereport.ashx?la=en>.

77 The market definition used for the TPS test includes all offers with costs less than or equal to 1.50 times the clearing price. See *MMU Technical Reference for PJM Markets*, at "Three Pivotal Supplier Test" for additional discussion.

Auctions, 36 participants out of 51 participants in the total PJM market passed the TPS test, eight participants out of 17 participants in the MAAC LDA market passed the TPS test, and all participants in the EMAAC and BGE LDA markets failed the TPS test. Offer caps were applied to all sell offers for resources which were subject to mitigation when the capacity market seller did not pass the test, the submitted sell offer exceeded the defined offer cap, and the submitted sell offer, absent mitigation, increased the market clearing price.[78 79 80]

In applying the market structure test, the relevant supply for the RTO market includes all supply offered at less than or equal to 150 percent of the RTO cost-based clearing price. The relevant supply for the constrained LDA markets includes the incremental supply inside the constrained LDAs which was offered at a price higher than the unconstrained clearing price for the parent LDA market and less than or equal to 150 percent of the cost-based clearing price for the constrained LDA. The relevant demand consists of the MW needed inside the LDA to relieve the constraint.

Table 5-9 presents the results of the TPS test. A generation owner or owners are pivotal if the capacity of the owners' generation facilities is needed to meet the demand for capacity. The results of the TPS are measured by the residual supply index (RSI_x). The RSI_x is a general measure that can be used with any number of pivotal suppliers. The subscript denotes the number of pivotal suppliers included in the test. If the RSI_x is less than or equal to 1.0, the supply owned by the specific generation owner, or owners, is needed to meet market demand and the generation owners are pivotal suppliers with a significant ability to influence market prices. If the RSI_x is greater than 1.0, the supply of the specific generation owner or owners is not needed to meet market demand and those generation owners have a reduced ability to unilaterally influence market price.

78 See OATT Attachment DD § 6.5.

79 Prior to November 1, 2009, existing DR and EE resources were subject to market power mitigation in RPM Auctions. See 129 FERC ¶ 61,081 at P 30 (2009).

80 Effective January 31, 2011, the RPM rules related to market power mitigation were changed, including revising the definition for planned generation capacity resource and creating a new definition for existing generation capacity resource for purposes of the must offer requirement and market power mitigation, and treating a proposed increase in the capability of a generation capacity resource the same in terms of mitigation as a planned generation capacity resource. See 134 FERC ¶ 61,065 (2011).

Table 5-9 RSI results: 2021/2022 through 2024/2025 RPM Auctions[81]

RPM Markets	$RSI_{1,\ 1.05}$	RSI_3	Total Participants	Failed RSI_3 Participants
2021/2022 Base Residual Auction				
RTO	0.80	0.68	122	122
EMAAC	0.71	0.22	14	14
PSEG	0.20	0.01	5	5
ATSI	0.01	0.00	2	2
ComEd	0.08	0.02	5	5
BGE	0.23	0.00	3	3
2021/2022 First Incremental Auction				
RTO	0.57	0.48	26	26
EMAAC	0.00	0.82	5	3
PSEG	0.00	0.00	1	1
PSEG North	0.00	0.00	2	2
BGE	0.00	0.00	1	1
2021/2022 Second Incremental Auction				
RTO	0.19	0.12	19	19
EMAAC	0.05	0.23	7	5
PSEG	0.00	0.00	2	2
BGE	0.00	0.00	0	0
2021/2022 Third Incremental Auction				
RTO	0.57	0.41	59	59
EMAAC	1.00	0.19	6	6
PSEG	0.00	0.00	1	1
BGE	0.00	-0.00	2	2
2022/2023 Base Residual Auction				
RTO	0.81	0.73	130	130
MAAC	0.69	0.37	25	25
EMAAC	1.25	0.64	7	7
ComEd	0.43	0.36	14	14
BGE	0.00	0.00	1	1
DEOK	0.00	0.00	1	1
2022/2023 Third Incremental Auction				
RTO	0.68	0.50	43	43
MAAC	0.40	0.05	9	9
2023/2024 Base Residual Auction				
RTO	0.78	0.68	134	134
MAAC	0.78	0.40	11	11
DPL South	0.00	0.00	1	1
BGE	0.00	0.00	1	1
2023/2024 Third Incremental Auction				
RTO	0.77	0.76	51	15
MAAC	0.41	0.76	17	9
EMAAC	0.45	0.18	10	10
BGE	0.00	0.00	1	1
2024/2025 Base Residual Auction				
RTO	0.77	0.64	133	133
MAAC	0.59	0.11	9	9
EMAAC	0.48	0.00	2	2
DPL South	0.00	0.00	1	1
BGE	0.00	0.00	1	1
DEOK	0.00	0.00	1	1

81 The RSI shown is the lowest RSI in the market.

Locational Deliverability Areas (LDAs)

Under the PJM Tariff, PJM determines, in advance of each BRA, whether defined Locational Deliverability Areas (LDAs) will be modeled in the auction. Effective with the 2012/2013 Delivery Year, an LDA is modeled as a potentially constrained LDA for a delivery year if the Capacity Emergency Transfer Limit (CETL) is less than 1.15 times the Capacity Emergency Transfer Objective (CETO), such LDA had a locational price adder in one or more of the three immediately preceding BRAs, or such LDA is determined by PJM in a preliminary analysis to be likely to have a locational price adder based on historic offer price levels. The rules also provide that starting with the 2012/2013 Delivery Year, EMAAC, SWMAAC, and MAAC LDAs are modeled as potentially constrained LDAs regardless of the results of the above three tests.[82] In addition, PJM may establish a constrained LDA even if it does not qualify under the above tests if PJM finds that "such is required to achieve an acceptable level of reliability."[83] A reliability requirement and a Variable Resource Requirement (VRR) curve are established for each modeled LDA. Effective for the 2014/2015 through 2016/2017 Delivery Years, a Minimum Annual and a Minimum Extended Summer Resource Requirement were established for each modeled LDA. Effective for the 2017/2018 Delivery Year, Sub-Annual and Limited Resource Constraints, replacing the Minimum Annual and a Minimum Extended Summer Resource Requirements, were established for each modeled LDA.[84] [85] Effective for the 2018/2019 and the 2019/2020 Delivery Years, a Base Capacity Demand Resource Constraint and a Base Capacity Resource Constraint, replacing the Sub-Annual and Limited Resource Constraints, were established for each modeled LDA.

Imports and Exports

Units external to the metered boundaries of PJM can qualify as PJM capacity resources if they meet the requirements to be capacity resources. Generators on the PJM system that do not have a commitment to serve PJM loads in the given delivery year as a result of RPM auctions, FRR capacity plans, locational UCAP transactions, and/or are not designated as a replacement resource, are eligible to export their capacity from PJM.[86]

The market rules in other balancing authorities should also not create inappropriate barriers to the import or export of capacity. The PJM market rules should ensure that the definition of capacity is enforced including physical deliverability, recallability and the obligation to make competitive offers into the PJM Day-Ahead Energy Market equal to ICAP MW. Physical deliverability can only be assured by requiring that all imports are deliverable to PJM load to ensure that they are full substitutes for internal capacity resources. Selling capacity into the PJM Capacity Market but making energy offers daily of $999 per MWh would not fulfill the requirements of a capacity resource to make a competitive offer, but would constitute economic withholding. This is one of the reasons that the rules governing the obligation to make a competitive offer in the day-ahead energy market should be clarified for both internal and external resources. The PJM market rules should also not create inappropriate barriers to either the import or export of capacity.

The calculation of CETL should only include capacity imports into PJM where the capacity has an explicit must offer requirement in the PJM capacity market. These could include pseudo tied units or resources with a grandfathered obligation. The external capacity that does not have a must offer requirement in the PJM capacity market is not obligated to serve PJM load under all conditions and therefore should not be assumed to be a source of capacity. This capacity should not be included in PJM's power flow calculations used to deriver CETL values between PJM's LDAs. PJM has modified its CETL calculations to exclude such capacity.

The establishment of a pseudo tie is one requirement for an external resource to be eligible to participate in the PJM Capacity Market. Pseudo tied external resources, regardless of their location, are treated as only meeting the reliability requirements of the rest of RTO and not the reliability requirements of any specific locational deliverability area (LDA). All imports offered in the auction from areas external to PJM are modeled as supply in the rest of RTO and not in any specific zonal or subzonal LDA. The fact that pseudo tied external

82 Prior to the 2012/2013 Delivery Year, an LDA with a CETL less than 1.05 times CETO was modeled as a constrained LDA in RPM. No additional criteria were used in determining modeled LDAs.
83 OATT Attachment DD § 5.10 (a) (ii).
84 146 FERC ¶ 61,052 (2014).
85 Locational Deliverability Areas are shown in maps in the *2021 Annual State of the Market Report for PJM*, Section 5 , "Capacity Market" at "Locational Deliverability Areas (LDAs)".
86 OATT Attachment DD § 5.6.6(b).

resources cannot be identified as equivalent to resources internal to specific LDAs illustrates a fundamental issue with capacity imports. Capacity imports are not equivalent to, nor substitutes for, internal resources. All internal resources are internal to a specific LDA.[87]

Effective May 9, 2017, significantly improved pseudo tie requirements for external generation capacity resources were implemented.[88] The rule changes include: defining coordination with other Balancing Authorities when conducting pseudo tie studies; establishing an electrical distance requirement; establishing a market to market flowgate test to establish limits on the number of coordinated flowgates PJM must add in order to accommodate a new pseudo tie; a model consistency requirement; the requirement for the capacity market seller to provide written acknowledgement from the external Balancing Authority Areas that such pseudo tie does not require tagging and that firm allocations associated with any coordinated flowgates applicable to the external Generation Capacity Resource under any agreed congestion management process then in effect between PJM and such Balancing Authority Area will be allocated to PJM; the requirement for the capacity market seller to obtain long-term firm point to point transmission service for transmission outside PJM with rollover rights and to obtain network external designated transmission service for transmission within PJM; establishing an operationally deliverable standard; and modifying the nonperformance penalty definition for external generation capacity resources to assess performance at subregional transmission organization granularity.

Generation external to the PJM region is eligible to be offered into an RPM auction if it meets specific requirements.[89] [90] [91] Firm transmission service must be acquired from all external transmission providers between the unit and border of PJM and generation deliverability into PJM must be demonstrated prior to the start of the delivery year. In order to demonstrate generation deliverability into PJM, external generators must obtain firm point to point transmission service on the PJM OASIS from the PJM border into the PJM transmission system or by obtaining network external designated transmission service. In the event that transmission upgrades are required to establish deliverability, those upgrades must be completed by the start of the delivery year. The following are also required: the external generating unit must be in the resource portfolio of a PJM member; 12 months of NERC/GADs unit performance data must be provided to establish an EFORd; the net capability of each unit must be verified through winter and summer testing; and a letter of non-recallability must be provided to assure PJM that the energy and capacity from the unit is not recallable to any other balancing authority.

All external generation resources that have an RPM commitment or FRR capacity plan commitment or that are designated as replacement capacity must be offered in the PJM day-ahead energy market.[92]

Planned External Generation Capacity Resources are eligible to be offered into an RPM Auction if they meet specific requirements.[93] [94] Planned External Generation Capacity Resources are proposed Generation Capacity Resources, or a proposed increase in the capability of an Existing Generation Capacity Resource, that is located outside the PJM region; participates in the generation interconnection process of a balancing authority external to PJM; is scheduled to be physically and electrically interconnected to the transmission facilities of such balancing authority on or before the first day of the delivery year for which the resource is to be committed to satisfy the reliability requirements of the PJM region; and is in full commercial operation prior to the first day of the delivery year.[95] An External Generation Capacity Resource becomes an Existing Generation Capacity Resource as of the earlier of the date that interconnection service commences or the resource has cleared an RPM Auction for a prior delivery year.[96]

87 External resources are not assigned to any of the five global LDAs or 22 zonal and subzonal LDAs. PJM's current practice is to model external resources in the rest of RTO. The practice is not currently documented by PJM. It was previously documented in "PJM Manual 18: PJM Capacity Market," § 2.3.4 Capacity Import Limits, Rev. 39 (December 21, 2017).
88 161 FERC ¶ 61,197 (2017).
89 See "Reliability Assurance Agreement Among Load Serving Entities in the PJM Region," Schedule 9 & 10.
90 "PJM Manual 18: PJM Capacity Market," § 4.2.2 Existing Generation Capacity Resources – External, Rev. 55 (Feb. 9, 2023).
91 "PJM Manual 18: PJM Capacity Market," § 4.6.4 Importing an External Generation Resource, Rev. 55 (Feb. 9, 2023).
92 OATT Schedule 1 § 1.10.1A.
93 See "Reliability Assurance Agreement among Load Serving Entities in the PJM Region," Section 1.69A.
94 "PJM Manual 18: PJM Capacity Market," § 4.2.4 Planned Generation Capacity Resources – External, Rev. 55 (Feb. 9, 2023).
95 Prior to January 31, 2011, capacity modifications to existing generation capacity resources were not considered planned generation capacity resources. See 134 FERC ¶ 61,065 (2011).
96 Effective January 31, 2011, the RPM rules related to market power mitigation were changed, including revising the definition for Planned Generation Capacity Resource for purposes of the must-offer requirement and market power mitigation. See 134 FERC ¶ 61,065 (2011).

As shown in Table 5-10, of the 1,527.1 MW of imports offered in the 2024/2025 RPM Base Residual Auction, 1,397.6 MW cleared. Of the cleared imports, 820.4 MW (58.7 percent) were from MISO.

Table 5-10 RPM imports: 2007/2008 through 2024/2025 RPM Base Residual Auctions

	UCAP (MW)					
	MISO		Non-MISO		Total Imports	
Base Residual Auction	Offered	Cleared	Offered	Cleared	Offered	Cleared
2007/2008	1,073.0	1,072.9	547.9	547.9	1,620.9	1,620.8
2008/2009	1,149.4	1,109.0	517.6	516.8	1,667.0	1,625.8
2009/2010	1,189.2	1,151.0	518.8	518.1	1,708.0	1,669.1
2010/2011	1,194.2	1,186.6	539.8	539.5	1,734.0	1,726.1
2011/2012	1,862.7	1,198.6	3,560.0	3,557.5	5,422.7	4,756.1
2012/2013	1,415.9	1,298.8	1,036.7	1,036.7	2,452.6	2,335.5
2013/2014	1,895.1	1,895.1	1,358.9	1,358.9	3,254.0	3,254.0
2014/2015	1,067.7	1,067.7	1,948.8	1,948.8	3,016.5	3,016.5
2015/2016	1,538.7	1,538.7	2,396.6	2,396.6	3,935.3	3,935.3
2016/2017	4,723.1	4,723.1	2,770.6	2,759.6	7,493.7	7,482.7
2017/2018	2,624.3	2,624.3	2,320.4	1,901.2	4,944.7	4,525.5
2018/2019	2,879.1	2,509.1	2,256.7	2,178.8	5,135.8	4,687.9
2019/2020	2,067.3	1,828.6	2,276.1	2,047.3	4,343.4	3,875.9
2020/2021	2,511.8	1,671.2	2,450.0	2,326.0	4,961.8	3,997.2
2021/2022	2,308.4	1,909.9	2,162.0	2,141.9	4,470.4	4,051.8
2022/2023	954.9	954.9	603.1	603.1	1,558.0	1,558.0
2023/2024	967.9	836.5	560.1	560.1	1,528.0	1,396.6
2024/2025	949.9	820.4	577.2	577.2	1,527.1	1,397.6

Demand Resources

The level of DR products that buy out of their positions after the BRA means that the treatment of DR has a negative impact on generation investment incentives and that the rules governing the requirement to be a physical resource should be more clearly stated and enforced.[97] If DR displaces new generation resources in BRAs, but then buys out of the position prior to the delivery year, this means potentially replacing new entry generation resources at the high end of the supply curve with other existing but uncleared capacity resources available in Incremental Auctions at reduced offer prices. This suppresses the price of capacity in the BRA compared to the competitive result because it permits the shifting of demand from the BRA to the Incremental Auctions, which is inconsistent with the must offer, must buy rules, and the requirement to be an actual, physical resource, governing the BRA. PJM's sell back of capacity in Incremental Auctions exacerbates the incentive for DR to buy out of its BRA positions in IAs.

There are two categories of demand side products included in the RPM market design:[98] [99]

- **Demand Resources (DR).** Interruptible load resource that is offered in an RPM Auction as capacity and receives the relevant LDA or RTO resource clearing price.
- **Energy Efficiency (EE) Resources.** Load resources that are offered in an RPM Auction as capacity and receive the relevant LDA or RTO resource clearing price. An EE Resource is a project designed to achieve a continuous (during peak periods) reduction in electric energy consumption during peak periods that is not reflected in the peak load forecast for the delivery year for which the EE is proposed, and that is fully implemented at all times during the relevant delivery year, without any requirement of notice, dispatch, or operator intervention.[100] The peak period definition for the EE Resource type is even more limited than Limited DR, including only the period from the hour ending (HE) 1500 and the HE 1800 from June through August, excluding weekends and federal holidays. The EE Resource type was eligible to be offered in RPM auctions starting with the 2012/2013 Delivery Year and in Incremental Auctions in the 2011/2012 Delivery Year.[101]

97 See "Analysis of Replacement Capacity for RPM Commitments: June 1, 2007 to June 1, 2019," <http://www.monitoringanalytics.com/reports/Reports/2019/IMM_Analysis_of_Replacement_Capacity_for_RPM_Commitments_June_1_2007_to_June_1_2019_20190913.pdf> (September 13, 2019).

98 Effective June 1, 2007, the PJM Active Load Management (ALM) program was replaced by the PJM Load Management (LM) program. Under ALM, providers had received a MW credit which offset their capacity obligation. With the introduction of LM, qualifying load management resources can be offered in RPM Auctions as capacity resources and receive the clearing price.

99 Interruptible load for reliability (ILR) is an interruptible load resource that is not offered into the RPM Auction, but receives the final zonal ILR price determined after the Second Incremental Auction. The ILR product was eliminated as of the 2012/2013 Delivery Year.

100 "Reliability Assurance Agreement Among Load Serving Entities in the PJM Region," Schedule 6, Section L.

101 Letter Order in Docket No. ER10-366-000 (January 22, 2010).

Effective with the 2020/2021 Delivery Year, the Capacity Performance product includes two possible season types, annual and summer.

- Annual Capacity Performance Resources
  - **Annual Demand Resources.** A Demand Resource that is required to be available on any day during the Delivery Year for an unlimited number of interruptions. Annual DR is required to be capable of maintaining each interruption between the hours of 10:00 a.m. and 10:00 p.m. EPT for the months of June through October and the following May and between the hours of 6:00 a.m. and 9:00 p.m. EPT for the months of November through April unless there is a PJM approved maintenance outage during the October through April period.
  - **Annual Energy Efficiency Resources.** A project designed to achieve a continuous (during summer and winter peak periods) reduction in electric energy consumption during peak periods that is not reflected in the peak load forecast for the delivery year for which the Energy Efficiency Resource is proposed, and that is fully implemented at all times during the relevant delivery year, without any requirement of notice, dispatch, or operator intervention. The peak period definition for the Annual Efficiency Resource type includes the period between the HE 1500 EPT and the HE 1800 EPT from June through August, and between the HE 0800 EPT and the HE 0900 EPT and between the HE 1900 EPT and the HE 2000 EPT from January 1 through February 28, excluding weekends and federal holidays.
- Seasonal Capacity Performance Resources
  - **Summer-Period Demand Resources.** A Demand Resource that is required to be available on any day from June through October and the following May of the delivery year for an unlimited number of interruptions. Summer Period DR is required to be capable of maintaining each interruption between the hours of 10:00 a.m. to 10:00 p.m. EPT.
  - **Summer-Period Energy Efficiency Resources.** A project designed to achieve a continuous (during summer peak periods) reduction in electric energy consumption during peak periods that is not reflected in the peak load forecast for the delivery year for which the Energy Efficiency Resource is proposed, and that is fully implemented at all times during the relevant delivery year, without any requirement of notice, dispatch, or operator intervention. The peak period definition for the Summer-Period Efficiency Resource type includes the period from the HE 1500 EPT and the HE 1800 EPT from June through August, excluding weekends and federal holidays.

As shown in Table 5-11, Table 5-12, and Table 5-13, capacity in the RPM load management programs was 14,027.0 MW for June 1, 2022, as a result of cleared capacity for demand resources and energy efficiency resources in RPM auctions for the 2022/2023 Delivery Year (14,601.0 MW) less replacement capacity (574.0 MW).

Table 5-11 RPM load management statistics by LDA: June 1, 2020 to June 1, 2024[102] [103] [104]

		UCAP (MW)														
		RTO	MAAC	EMAAC	SWMAAC	DPL South	PSEG	PSEG North	Pepco	ATSI	ATSI Cleveland	ComEd	BGE	PPL	DAY	DEOK
01-Jun-20	DR cleared	9,445.7	2,829.1	1,168.9	485.8	72.6	339.0	152.7	236.3	951.7	231.9	1,657.3	249.5	616.6	241.5	184.7
	EE cleared	3,569.5	1,288.8	700.3	394.5	28.8	246.1	111.3	196.2	356.0	72.9	852.0	198.3	111.4	79.5	105.6
	DR net replacements	(2,399.5)	(858.7)	(369.0)	(176.5)	(29.7)	(136.5)	(89.0)	(53.3)	(121.1)	(36.2)	(314.5)	(123.2)	(171.0)	(66.1)	(27.5)
	EE net replacements	(29.7)	(0.5)	(0.3)	5.9	0.0	(6.3)	12.0	(0.6)	(0.2)	0.0	(0.1)	6.5	(5.2)	0.0	(5.0)
	RPM load management	10,586.0	3,258.7	1,499.9	709.7	71.7	442.3	187.0	378.6	1,186.4	268.6	2,194.7	331.1	551.8	254.9	257.8
01-Jun-21	DR cleared	11,427.7	3,454.1	1,381.5	624.9	66.3	410.5	188.6	345.9	1,196.8	272.8	2,073.7	279.0	697.7	227.7	220.5
	EE cleared	4,806.2	1,810.5	979.1	501.1	42.0	353.1	136.0	275.9	420.5	95.7	982.7	225.2	186.7	111.0	135.5
	DR net replacements	(4,111.0)	(1,302.8)	(568.4)	(160.8)	(28.1)	(195.8)	(100.2)	(106.5)	(483.2)	(137.4)	(609.5)	(54.3)	(235.1)	(50.9)	(90.2)
	EE net replacements	(7.0)	0.0	0.0	(1.1)	0.1	0.0	34.9	(2.6)	80.0	7.0	10.6	1.5	(1.7)	8.0	(17.5)
	RPM load management	12,115.9	3,961.8	1,792.2	964.1	80.3	567.8	259.3	512.7	1,214.1	238.1	2,457.5	451.4	647.6	295.8	248.3
01-Jun-22	DR cleared	8,866.2	2,821.3	1,139.9	489.2	48.4	294.6	93.8	325.3	949.4	191.8	1,521.9	163.9	661.7	210.5	185.1
	EE cleared	5,734.8	2,303.6	1,265.3	499.4	53.5	431.0	201.6	287.5	485.0	55.9	792.6	211.9	312.4	129.4	186.8
	DR net replacements	(570.0)	(395.4)	(138.0)	(12.6)	1.7	(49.4)	(12.6)	(21.5)	(99.6)	(28.2)	127.5	8.9	(165.2)	(24.1)	24.3
	EE net replacements	(4.0)	11.8	7.0	14.9	0.0	(2.1)	15.4	8.7	(22.2)	(0.5)	0.0	6.2	(9.8)	(13.0)	0.0
	RPM load management	14,027.0	4,741.3	2,274.2	990.9	103.6	674.1	298.2	600.0	1,312.6	219.0	2,442.0	390.9	799.1	302.8	396.2
01-Jun-23	DR cleared	8,174.1	2,411.4	975.9	343.6	52.2	272.7	126.1	175.2	916.2	189.4	1,253.2	168.4	583.4	209.3	175.4
	EE cleared	5,896.4	2,438.6	1,341.4	569.5	59.3	443.4	210.4	298.6	451.8	46.3	961.2	270.9	306.1	102.4	164.3
	DR net replacements	(4.2)	(2.5)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	(2.5)	0.0	0.0
	EE net replacements	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	RPM load management	14,066.3	4,847.5	2,317.3	913.1	111.5	716.1	336.5	473.8	1,368.0	235.7	2,214.4	439.3	887.0	311.7	339.7
01-Jun-24	DR cleared	7,992.7	2,505.1	1,001.0	362.6	42.1	285.7	98.2	164.5	674.6	141.6	1,542.0	198.1	608.7	191.1	221.9
	EE cleared	7,668.7	3,500.1	2,030.3	779.2	99.9	771.4	376.1	398.9	587.3	54.9	1,063.4	380.3	392.9	128.3	188.1
	DR net replacements	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	EE net replacements	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	RPM load management	15,661.4	6,005.2	3,031.3	1,141.8	142.0	1,057.1	474.3	563.4	1,261.9	196.5	2,605.4	578.4	1,001.6	319.4	410.0

102 See OATT Attachment DD § 8.4. The reported DR cleared MW may reflect reductions in the level of committed MW due to relief from Capacity Resource Deficiency Charges.

103 Pursuant to OA § 15.1.6(c), PJM Settlement shall attempt to close out and liquidate forward capacity commitments for PJM Members that are declared in collateral default. The reported replacement transactions may include transactions associated with PJM members that were declared in collateral default.

104 See OATT Attachment DD § 5.14E. The reported DR cleared MW for the 2016/2017, 2017/2018, and 2018/2019 Delivery Years reflect reductions in the level of committed MW due to the Demand Response Legacy Direct Load Control Transition Provision.

Table 5-12 RPM commitments, replacements, and registrations for demand resources: June 1, 2007 to June 1, 2024[105 106 107]

	UCAP (MW)						Registered DR		
	RPM Cleared	Adjustments to Cleared	Net Replacements	RPM Commitments	RPM Commitment Shortage	RPM Commitments Less Commitment Shortage	ICAP (MW)	UCAP Conversion Factor	UCAP (MW)
01-Jun-07	127.6	0.0	0.0	127.6	0.0	127.6	0.0	1.033	0.0
01-Jun-08	559.4	0.0	(40.0)	519.4	(58.4)	461.0	488.0	1.034	504.7
01-Jun-09	892.9	0.0	(474.7)	418.2	(14.3)	403.9	570.3	1.033	589.2
01-Jun-10	962.9	0.0	(516.3)	446.6	(7.7)	438.9	572.8	1.035	592.6
01-Jun-11	1,826.6	0.0	(1,052.4)	774.2	0.0	774.2	1,117.9	1.035	1,156.5
01-Jun-12	8,752.6	(11.7)	(2,253.6)	6,487.3	(34.9)	6,452.4	7,443.7	1.037	7,718.4
01-Jun-13	10,779.6	0.0	(3,314.4)	7,465.2	(30.5)	7,434.7	8,240.1	1.042	8,586.8
01-Jun-14	14,943.0	0.0	(6,731.8)	8,211.2	(219.4)	7,991.8	8,923.4	1.042	9,301.2
01-Jun-15	15,774.8	(321.1)	(4,829.7)	10,624.0	(61.8)	10,562.2	10,946.0	1.038	11,360.0
01-Jun-16	13,284.7	(19.4)	(4,800.7)	8,464.6	(455.4)	8,009.2	8,961.2	1.042	9,333.4
01-Jun-17	11,870.7	0.0	(3,870.8)	7,999.9	(30.3)	7,969.6	8,681.4	1.039	9,016.3
01-Jun-18	11,435.4	0.0	(3,182.4)	8,253.0	(1.0)	8,252.0	8,512.0	1.091	9,282.4
01-Jun-19	10,703.1	0.0	(2,138.8)	8,564.3	(0.4)	8,563.9	9,229.9	1.090	10,056.0
01-Jun-20	9,445.7	0.0	(2,399.5)	7,046.2	(0.1)	7,046.1	7,867.6	1.088	8,561.5
01-Jun-21	11,427.7	0.0	(4,111.0)	7,316.7	0.0	7,316.7	7,754.2	1.087	8,429.6
01-Jun-22	8,866.2	0.0	(570.0)	8,296.2	(52.1)	8,244.1	8,510.7	1.091	9,281.7
01-Jun-23	8,174.1	0.0	(4.2)	8,169.9	0.0	8,169.9	52.6	1.093	57.5
01-Jun-24	7,992.7	0.0	0.0	7,992.7	0.0	7,992.7	0.0	1.089	0.0

105 See OATT Attachment DD § 8.4. The reported DR adjustments to cleared MW include reductions in the level of committed MW due to relief from Capacity Resource Deficiency Charges.
106 See OATT Attachment DD § 5.14C. The reported DR adjustments to cleared MW for the 2015/2016 and 2016/2017 Delivery Years include reductions in the level of committed MW due to the Demand Response Operational Resource Flexibility Transition Provision.
107 See OATT Attachment DD § 5.14E. The reported DR adjustments to cleared MW for the 2016/2017, 2017/2018, and 2018/2019 Delivery Years include reductions in the level of committed MW due to the Demand Response Legacy Direct Load Control Transition Provision.

Table 5-13 RPM commitments and replacements for energy efficiency resources: June 1, 2007 to June 1, 2024[108] [109]

	UCAP (MW)					
	RPM Cleared	Adjustments to Cleared	Net Replacements	RPM Commitments	RPM Commitment Shortage	RPM Commitments Less Commitment Shortage
01-Jun-07	0.0	0.0	0.0	0.0	0.0	0.0
01-Jun-08	0.0	0.0	0.0	0.0	0.0	0.0
01-Jun-09	0.0	0.0	0.0	0.0	0.0	0.0
01-Jun-10	0.0	0.0	0.0	0.0	0.0	0.0
01-Jun-11	76.4	0.0	0.2	76.6	0.0	76.6
01-Jun-12	666.1	0.0	(34.9)	631.2	(5.1)	626.1
01-Jun-13	904.2	0.0	120.6	1,024.8	(13.5)	1,011.3
01-Jun-14	1,077.7	0.0	204.7	1,282.4	(0.2)	1,282.2
01-Jun-15	1,189.6	0.0	335.9	1,525.5	(0.9)	1,524.6
01-Jun-16	1,723.2	0.0	61.1	1,784.3	(0.5)	1,783.8
01-Jun-17	1,922.3	0.0	195.6	2,117.9	(7.4)	2,110.5
01-Jun-18	2,296.3	0.0	248.8	2,545.1	0.0	2,545.1
01-Jun-19	2,528.5	0.0	(50.0)	2,478.5	0.0	2,478.5
01-Jun-20	3,569.5	0.0	(29.7)	3,539.8	(0.1)	3,539.7
01-Jun-21	4,806.2	0.0	(7.0)	4,799.2	0.0	4,799.2
01-Jun-22	5,734.8	0.0	(4.0)	5,730.8	0.0	5,730.8
01-Jun-23	5,896.4	0.0	0.0	5,896.4	0.0	5,896.4
01-Jun-24	7,668.7	0.0	0.0	7,668.7	0.0	7,668.7

Capacity Value of Intermittent Resources (ELCC)

Given that states have increasingly aggressive renewable energy targets, a core goal of a competitive market design should be to ensure that the resources required to provide reliability receive appropriate competitive market incentives for entry and for ongoing investment and for exit when uneconomic. A significant level of renewable resources, operating with zero or near zero marginal costs, will result in very low energy prices. Since renewable resources are intermittent, the contribution of renewables to meeting reliability targets must be analyzed carefully to ensure that the capacity value of renewables is calculated correctly.

The contribution of intermittent and storage resources to reliability has been addressed in the PJM capacity market using derating factors in order to help ensure that MW of capacity are comparable, regardless of the source. Derating factors were used in the 2022/2023 BRA. On July 30, 2021, FERC approved new rules in PJM for determining the capacity value of intermittent generators based on the effective load carrying capability (ELCC) method.[110] The MMU opposed the new ELCC rules because they fail to incorporate the marginal ELCC value of resources, rely on significant counterfactual behavioral assumptions, do not apply to all resource types, and use invented (putative) data as key inputs, among other issues.[111] PJM's flawed ELCC approach will create new issues for the PJM capacity markets unless addressed promptly.

PJM's flawed ELCC approach, based on static average rather than dynamic, market defined marginal values and basing the results on incorrect assumptions about the dispatch of some resource types, will create new issues for the PJM capacity markets unless addressed in the near future.

The ELCC approach is not an appropriate way to define the MW capacity value for intermittent and storage resources, or for thermal resources, in a market. ELCC was developed as, and remains, a utility planning tool rather than a market design tool. ELCC was attractive as a possible analytical basis for the derating of intermittent and storage resources to a MW level consistent with their actual availability and consistent with a perfect resource, or at least a thermal resource. The impetus made sense but the actual application of the ELCC planning tool cannot work in markets that include intermittent or thermal resources. The underlying logic makes sense. Neither intermittent nor thermal resources are the perfect resource. There are thermal resources, currently credited with full capacity value, that are much less available than some intermittent resources that are derated.

If ELCC is used, the correct application of ELCC, from a mathematical and economic perspective, is to define ELCC as the marginal ELCC. It is clear

108 Pursuant to the OA § 15.1.6(c), PJM Settlement shall close out and liquidate all forward positions of PJM members that are declared in default. The replacement transactions reported for the 2014/2015 Delivery Year included transactions associated with RTP Controls, Inc., which was declared in collateral default on March 9, 2012.

109 Effective with the 2019/2020 Delivery Year, available capacity from an EE Resource can be used to replace only EE Resource commitments. This rule change and related EE addback rule changes were endorsed at the December 17, 2015, meeting of the PJM Markets and Reliability Committee.

110 See 176 FERC ¶ 61,056 (2021). There are multiple ways to apply the ELCC method. There is not a single ELCC method.

111 Comments and Motions of the Independent Market Monitor for PJM, Docket No. ER21-278 and EL19-100 (November 20, 2020). Answer and Motion for Leave to Answer and Alternative Motion for Consolidation of the Independent Market Monitor for PJM, Docket No. ER21-278 (December 10, 2020). Answer and Motion for Leave to Answer of the Independent Market Monitor for PJM, Docket No. ER21-278 (December 18, 2020). Comments and Motions of the Independent Market Monitor for PJM, ER21-278-001 (March 22, 2021). Answer and Motion for Leave to Answer of the Independent Market Monitor for PJM, Docket No. ER21-278 (April 28, 2021).

that as the market share of intermittents grows, the marginal value of intermittents will decrease quickly. The result will be that a 100 MW solar resource will have a very small capacity value, e.g. 5 MW, but have a performance obligation, and associated penalty exposure, equal to its full CIRs of 100 MW. The competitive offer of that capacity will be high because it is the full annual net avoidable cost divided by 5 MW and not by 100 MW. That tension between the derated MW that qualify as capacity and can be sold in the capacity market, and the obligation to perform, will make offering intermittent resources as capacity increasingly untenable. That tension does not reflect the economic or reliability value of the intermittent resources. This is not an argument for average ELCC, which is clearly wrong. It is an argument for abandoning ELCC as the definition of capacity for intermittents or for thermals and replacing ELCC with a metric that reflects the actual availability of all resource types. This will ensure comparable treatment within and across categories of capacity resources.

Derating factors and ELCC values are used in capacity auctions to convert the nameplate capacity of intermittent and storage resources into MW of capacity equivalent to resources that can produce for any of the 8,760 hours in a year. The capacity derating factors applied to intermittent nameplate capacity in the 2022/2023 BRA and the ELCC calculations used in the 2023/2024 BRA and the 2024/2025 BRA are based on the assumption that the intermittent resources provide reliable output in excess of their CIRs. But that output is not deliverable when needed for reliability because it is in excess of the defined deliverability rights (CIRs) and therefore should not be included in the definition of intermittent capacity. The preferable solution is to require intermittent resources to purchase CIRs equal to the maximum energy output assumed in the derating calculation. That is the solution reached in the PJM stakeholder process.[112] The corresponding performance obligation of an intermittent resource is to produce at its corresponding maximum energy output level when it is possible, based on wind and solar conditions. After a lengthy stakeholder process, on April 7, 2023, FERC approved updates to PJM's ELCC method that cap the level of an intermittent generator's output used to calculate the generator's reliability contribution (ELCC derated MW) at the generator's CIR level. [113]

The definition of intermittent capacity is thus not consistent with the way that capacity is defined. This results in an overstatement of the supply of capacity and reduces the clearing price in the capacity market. The MMU recommends that intermittent resources, including storage, not be permitted to offer capacity MW based on energy delivery that exceeds their defined deliverability rights (CIRs). Only energy output for such resources below the designated CIR/deliverability level should be recognized in the definition of capacity. There is the related issue of ensuring that intermittent resources, like all other resources, are required to pay their own interconnection costs in order to meet their attributed capacity value, consistent with the longstanding PJM market design, or reduce their capacity value.

Generation owners of intermittent resources and environmentally limited resources can request winter capacity interconnection rights (CIRs). If the intermittent resource or environmentally limited resource is deemed deliverable by PJM based on the additional CIRs, the generation owner is granted the additional CIRs for the winter period of the relevant delivery year. Winter seasonal products have the ability to inject more MW in the winter because the lower peak loads in the winter allow higher injections from certain resources without needing any additional network upgrades. But this system capacity in the winter is already paid for by resources that applied for needed network upgrades to inject in the summer to meet the annual peak loads that are expected to occur in the summer.

PJM's practice of giving away winter CIRs, that appear to be available because other resources paid for the supporting network upgrades, requires annual capacity resources to subsidize the interconnection costs of intermittent resources and artificially increases the capacity value of the winter resources. Those CIRs are not available to be sold to or provided to intermittent resources because they have been paid for by annual resources. The MMU recommends that PJM require all market participants to meet their deliverability requirements under the same rules.

112 ELCC/CIR discussions were held throughout 2022 during the PC Special Session – CIRs for ELCC Resources as well as the MC and the MRC <https://www.pjm.com/committees-and-groups/issue-tracking/issue-tracking-details.aspx?Issue=83aadda8-b6c1-4630-9483-025b6b93fc28>.

113 183 FERC ¶61,009.

Market Conduct

Offer Caps

Market power mitigation measures were applied to capacity resources such that the sell offer was set equal to the defined offer cap when the capacity market seller failed the market structure test for the auction, the submitted sell offer exceeded the defined offer cap, and the submitted sell offer, absent mitigation, would have increased the market clearing price.[114] [115] [116] For Capacity Performance Resources, for RPM auctions prior to September 2, 2021, offer caps are defined in the PJM Tariff as the applicable zonal Net Cost of New Entry (CONE) times (B) where B is the average of the Balancing Ratios (B) during the Performance Assessment Hours in the three consecutive calendar years that precede the base residual auction for such delivery year, unless net avoidable costs exceed this level, or opportunity costs based on the potential sale of capacity in an external market exceed this level. The Commission issued an order eliminating the prior offer cap and establishing a competitive market seller offer cap set at Net ACR, effective September 2, 2021.[117] For RPM Third Incremental Auctions prior to September 2, 2021, capacity market sellers may elect an offer cap equal to the greater of the Net CONE for the relevant LDA and delivery year or 1.1 times the BRA clearing price for the relevant LDA and delivery year. For RPM Third Incremental Auctions after September 2, 2021, capacity market sellers may elect an offer cap of 1.1 times the BRA clearing price for the relevant LDA and delivery year.

Avoidable costs are costs that are neither short run marginal costs, like fuel or consumables, nor fixed costs like depreciation and rate of return. Avoidable costs are the costs that a generation owner incurs as a result of operating a generating unit for one year, in particular the delivery year.[118] As a result, the tariff defines avoidable costs as the costs that a generation owner would not incur if the generating unit did not offer for one year. Although the term mothball is used in the tariff to modify the term ACR, the term mothball is not defined in the tariff. Mothball is an informal term better understood as a metaphor for the cost to operate for one year. Avoidable costs are the costs to operate the unit for one year, regardless of whether the unit plans to retire. Although the tariff includes different mothball and retirement values, the distinction is based on a misunderstanding of the meaning of avoidable costs and should be eliminated. PJM never explained exactly how it calculated mothball and retirement avoidable cost levels. The MMU recommends that major maintenance costs be included in the definition of avoidable costs and removed from energy offers because such costs are avoidable costs and not short run marginal costs.[119] The tariff states that avoidable costs may also include annual capital recovery associated with investments required to maintain a unit as a Generation Capacity Resource, termed Avoidable Project Investment Recovery (APIR), despite the fact that these are not actually avoidable costs, particularly after the first year.

Avoidable cost based offer caps are defined to be net of revenues from all other PJM markets and unit-specific bilateral contracts and expected bonus performance payments/nonperformance charges.[120] Capacity resource owners could provide ACR data by providing their own unit-specific data or, for auctions for delivery years prior to 2020/2021 and auctions held after September 2, 2021, by selecting the default ACR values. The specific components of avoidable costs are defined in the PJM tariff.[121]

Effective for the 2018/2019 and subsequent delivery years, the ACR definition includes two additional components, Avoidable Fuel Availability Expenses (AFAE) and Capacity Performance Quantifiable Risk (CPQR).[122] AFAE is available for Capacity Performance Resources. AFAE is defined to include expenses related to fuel availability and delivery. CPQR is available for Capacity Performance Resources and, for the 2018/2019 and 2019/2020 Delivery Years, Base Capacity Resources. CPQR is defined to be the quantifiable

114 See OATT Attachment DD § 6.5.
115 Prior to November 1, 2009, existing DR and EE resources were subject to market power mitigation in RPM Auctions. See 129 FERC ¶ 61,081 at P 30 (2009).
116 Effective January 31, 2011, the RPM rules related to market power mitigation were changed, including revising the definition for Planned Generation Capacity Resource and creating a new definition for Existing Generation Capacity Resource for purposes of the must offer requirement and market power mitigation, and treating a proposed increase in the capability of a Generation Capacity Resource the same in terms of mitigation as a Planned Generation Capacity Resource. See 134 FERC ¶ 61,065 (2011).
117 176 FERC ¶ 61,137 (2021).
118 OATT Attachment DD § 6.8 (b).
119 *PJM Interconnection L.L.C., Docket Nos. ER19-210-000 and EL19-8-000, Responses to Deficiency Letter re: Major Maintenance and Operating Costs Recovery* (February 14, 2019).
120 For details on the competitive offer of a capacity performance resource, see "Analysis of the 2023/2024 RPM Base Residual Auction," <https://www.monitoringanalytics.com/reports/Reports/2022/IMM_Analysis_of_the_20232024_RPM_Base_Residual_Auction_20221028.pdf>. (October 28, 2022).
121 OATT Attachment DD § 6.8(a).
122 151 FERC ¶ 61,208.

and reasonably supported cost of mitigating the risks of nonperformance associated with submission of an offer.

The opportunity cost option allows capacity market sellers to offer based on a documented price available in a market external to PJM, subject to export limits. If the relevant RPM market clears above the opportunity cost, the generation capacity resource is sold in the RPM market. If the opportunity cost is greater than the clearing price and the generation capacity resource does not clear in the RPM market, it is available to sell in the external market.

Competitive Offers

The competitive offer of a capacity resource is based, regardless of tariff requirements, on a market seller's expectations of a number of variables, some of which are resource specific: the resource's net going forward costs (net ACR) including gross ACR, forward looking net revenues and the impact of the resource's performance during performance assessment intervals (A) in the delivery year on its risk and the cost to mitigate that risk.[123]

The competitive offer is based on a forward looking energy and ancillary services (E&AS) net revenue offset rather than the backward looking E&AS net revenue offset currently in the tariff. Forward prices for energy prices and fuel costs are a better guide to market expectations of net revenues than an average of the actual net revenues for the last three years. This is particularly important in years, like 2022, when there is a significant change from the historical level of energy market prices and net revenues. The actual prices in 2022 are about 120 percent higher through the end of September than prices for the same period in 2021. The forward curves reflect this change, but the historical net revenues do not.

But the current PJM method for calculating forward looking E&AS net revenues includes an adjustment based on the prices of long term FTRs for the planning period closest in time to the delivery year which requires an adjustment for monthly average day-ahead congestion price differentials and an adjustment for loss component differentials of historical LMPs. Use of the adjustment based on the prices of long term FTRs adds unnecessary complexity, fails to make the result more accurate, makes the results less transparent, and in some cases make the results less accurate. PJM's use of long term FTRs in the forward energy market price calculation does not use the FTR auction for the desired delivery year as a result of the timing of capacity auctions and FTR auctions when PJM is on its defined three year capacity market auction schedule. It would be simpler, more accurate and more transparent to use forward LMPs calculated using real-time monthly on and off peak forward prices for the delivery year at the PJM Western Hub, adjusted to the zone and hour using the historical zonal, nodal and hourly real-time price differentials for each of the last three years. The MMU and PJM have been implementing this method for years in the calculation of the opportunity costs associated with environmental limits on the operation of generating units.[124]

The competitive offer of a capacity resource is based on a market seller's expectations of market variables during the delivery year, the impact of these variables on the resource's risk, and the cost to mitigate that risk. These market variables are: the number of performance assessment intervals (PAI) in a delivery year where the resource is located; the level of performance required to meet its capacity obligation during those performance assessment intervals, measured as the average Balancing Ratio (B); and the level of the bonus performance payment rate (CPBR) compared to the nonperformance charge rate (PPR). The total capacity revenues earned by a resource are the sum of revenues earned in the forward capacity auctions and additional bonus revenues earned (or penalties paid) during the delivery year, which are a function of unit performance during PAI (A). The level of the bonus performance payment rate depends on the level of underperforming MW net of the underperforming MW excused by PJM during performance assessment intervals for reasons defined in the PJM OATT.[125]

Under the original Capacity Performance design, the competitive offer of a resource was the larger of the asserted opportunity cost of taking on a CP obligation (the default offer cap), or a unit specific offer cap based on its net ACR. But the default offer cap defined in the PJM tariff was based on strong assumptions that are not correct.

123 The model is only applicable to generation resources and storage resources that have an annual obligation to perform with very limited specific excuses as defined in the PJM OATT.

124 *See* "PJM Manual 15: Cost Development Guidelines," § 12.7 IMM Opportunity Cost Calculator, Rev. 42 (Oct. 28, 2022).

125 OATT Attachment DD § 10A (d).

The circular logic of the offer cap derivation inevitably concluded that Net CONE times B was the competitive offer. The derivation is based on the assumption that Net CONE is the target clearing price for the capacity market. That assumption is the basis for using Net CONE as the penalty rate. The penalty rate, adjusted for the reduced obligation defined by B, equals the market seller offer cap. The derivation is also based on the assumption that capacity resources have the ability to costlessly switch between capacity resource status and energy only status. That assumption is the basis for the assertion that an offer in the capacity market has an opportunity cost associated with the ability to be an energy only resource. But there is no such opportunity cost. The use of the offer cap is also based on a third demonstrably false assumption that competitive forces in the PJM Capacity Market would produce competitive outcomes despite an offer cap that was above the competitive level.

The offer cap derivation also included some additional unsupported and incorrect assumptions: there are a reasonably expected number of PAI; the number of PAI used in the calculation of the nonperformance charge rate is the same as the expected PAI (360); the number of performance intervals that define the total payments must equal the denominator of the performance penalty rate; the bonus payment rate for units that overperform equals the penalty rate for units that underperform; and penalties are imposed by PJM for all cases of noncompliance as defined in the tariff and there are no excuses.

The PJM Capacity Market has a must offer requirement for a reason; it is required in order to ensure that the market can work, given the must buy obligation of load. A key ancillary benefit is that the must offer requirement helps prevent the exercise of market power by preventing withholding. If a capacity market seller wants to convert to energy only status, the owner must give up its CIRs. Such CIRs are likely to be expensive and difficult to reacquire if the capacity market seller decided to reenter the capacity market. There have been effectively zero true PAI since the introduction of the capacity performance model. This does not mean that there will never be PAI or that there will never be 360 PAI. It does mean that it is not reasonable to include the assumption of 360 PAI in establishing the definition of a competitive offer in the capacity market. It does mean that there is no accurate way to calculate expected PAI for the market and that a design based on that calculation will not be based on market fundamentals.

Net CONE times B was clearly well in excess of a competitive offer in the 2021/2022 BRA and 2022/2023 BRA whether compared to net ACR offers or compared to the actual offers of market participants. While the offer cap provided almost unlimited optionality to generation owners in setting offers, the actual clearing prices based on actual offers were generally about half of the offer caps. But some generation owners did successfully exercise market power within this design.

The September 2, 2021, Commission order addressed the definition of the market seller offer cap by eliminating the net CONE times B offer cap and establishing a competitive market seller offer cap of net ACR.

2024/2025 RPM Base Residual Auction

As shown in Table 5-14, 964 generation resources submitted offers in the 2024/2025 RPM Base Residual Auction. The MMU calculated unit specific ACR based offer caps for 21 generation resources (2.2 percent). Of the 964 generation capacity resources offered, 715 generation resources had default ACR based offer caps (74.2 percent), 21 generation resources had unit specific ACR based offer caps (2.2 percent), one generation resource had a unit specific opportunity cost based offer cap (0.1 percent), 17 Planned Generation Capacity Resources had uncapped offers (1.8 percent), five generation resources had uncapped planned uprates plus default ACR based offer caps for the existing portion of the units (0.5 percent), while the remaining 205 generation resources were price takers (21.3 percent). Market power mitigation was applied to 18 Capacity Performance sell offers.

2023/2024 RPM Third Incremental Auction

As shown in Table 5-14, 250 generation resources submitted Capacity Performance offers in the 2023/2024 RPM Third Incremental Auction. Unit specific offer caps were calculated for five generation resources (2.0 percent). Of the 250 generation resources, 177 generation resources elected the offer cap option of 1.1 times the BRA clearing price (70.8 percent), 48 generation resources had default ACR based offer caps (19.2 percent), four generation resources had unit specific ACR based offer caps (1.6 percent), one generation resource had a unit specific opportunity cost based offer cap (0.4 percent), two Planned Generation Capacity Resources had uncapped offers (0.8 percent), and the remaining 18 generation resources were price takers (7.2 percent). Market power mitigation was applied to five Capacity Performance sell offers.

Table 5-14 ACR statistics: RPM auctions held in first quarter, 2023

	2024/2025 Base Residual Auction		2023/2024 Third Incremental Auction	
Offer Cap/Mitigation Type	Number of Generation Resources	Percent of Generation Resources Offered	Number of Generation Resources	Percent of Generation Resources Offered
Default ACR	715	74.2%	48	19.2%
Unit specific ACR (APIR)	14	1.5%	4	1.6%
Unit specific ACR (APIR and CPQR)	6	0.6%	0	0.0%
Unit specific ACR (non-APIR)	1	0.1%	0	0.0%
Unit specific ACR (non-APIR and CPQR)	0	0.0%	0	0.0%
Opportunity cost input	1	0.1%	1	0.4%
Default ACR and opportunity cost	0	0.0%	0	0.0%
Net CONE times B	NA	NA	NA	NA
Offer cap of 1.1 times BRA clearing price elected	NA	NA	177	70.8%
Uncapped planned uprate and default ACR	5	0.5%	0	0.0%
Uncapped planned uprate and opportunity cost	0	0.0%	0	0.0%
Uncapped planned uprate and Net CONE times B	NA	NA	NA	NA
Uncapped planned uprate and price taker	0	0.0%	0	0.0%
Uncapped planned uprate and 1.1 times BRA clearing price elected	NA	NA	0	0.0%
Uncapped planned generation resources	17	1.8%	2	0.8%
Existing generation resources as price takers	205	21.3%	18	7.2%
Total Generation Capacity Resources offered	964	100.0%	250	100.0%

MOPR

By order issued December 19, 2019, the RPM Minimum Offer Price Rule (MOPR) was modified.[126] The order is pending review before the U.S. Court of Appeals for the Sixth Circuit.[127] The rules applying to natural gas fired capacity resources without state subsidies were retained. The changes included expanding the MOPR to new or existing state subsidized capacity resources; establishing a competitive exemption for new and existing resources other than natural gas fired resources while also allowing a resource specific exception process for those that do not qualify for the competitive exemption; defining limited categorical exemptions for renewable resources participating in renewable portfolio standards (RPS) programs, self supply, DR, EE, and capacity storage; defining the region subject to MOPR for capacity resources with state subsidy as the entire RTO; and defining the default offer price floor for capacity resources with state subsidies as 100 percent of the applicable Net CONE or net ACR values.

The Commission convened a Technical Conference on March 23, 2021, in order to consider whether MOPR should be retained and to consider possible alternative approaches.[128] The MMU testified at the Technical Conference and provided comments and responses to the Commission's questions following the conference.[129]

On September 29, 2021, PJM's FPA section 205 filing in Docket No. ER21-2582-000 revising the Minimum Offer Price Rule (MOPR) was made effective by operation of law.[130] The revised MOPR in OATT Attachment DD § 5.14(h-2) is effective for RPM auctions for the 2023/2024 and subsequent delivery years. Under the revised MOPR, a generation resource would be subject to an offer floor if the capacity is deemed to meet the definition of Conditioned State Support or if the capacity market seller plans to use the resource to exercise Buyer-Side Market Power as the term is defined in the tariff through either self certification or a fact specific review initiated by the MMU or PJM. Whether a state program or policy qualifies for Conditioned State Support would be the result of a Commission determination.

The MMU's filing in response to PJM's proposal was clear. The PJM markets would be better off, more competitive, and more efficient with no MOPR than with PJM's proposed approach. PJM's proposal would effectively eliminate

126 169 FERC ¶ 61,239 (2019), *order denying reh'g*, 171 FERC ¶ 61,035 (2020).
127 Case No. 22-3176, et al.

128 Technical Conference regarding Resource Adequacy in the Evolving Electricity Sector, Docket No. AD21-10 (March 23, 2021).
129 *Modernizing Electricity Market Design*, Comments of the Independent Market Monitor for PJM, Docket No. AD21-10 (April 26, 2021).
130 *PJM Interconnection, L.L.C*, Notice of Filing Taking Effect by Operation of Law, Docket No. ER21-2582 (September 29, 2021).

the MOPR while creating a confusing and inefficient administrative process that effectively makes it both unnecessary and impossible to prove buyer side market power as PJM has defined it.[131]

The Commission approved PJM's proposed revisions to the PJM market rules to implement a forward looking EAS offset to include forward looking energy and ancillary services revenues rather than historical.[132] The change in the offset affected MOPR floor prices and the results of unit specific reviews under MOPR in the 2023/2024 BRA. This decision was reversed in the Commission's order related to the ORDC matter.[133]

MOPR Statistics

Under the applicable MOPR rules, market power mitigation measures were applied to MOPR Screened Generation Resources such that the sell offer is set equal to the MOPR Floor Offer Price when the submitted sell offer is less than the MOPR Floor Offer Price and an exemption or exception was not granted, or the sell offer is set equal to the agreed upon minimum level of sell offer when the sell offer is less than the agreed upon minimum level of sell offer based on a Unit-Specific Exception or Resource-Specific Exception.

As shown in Table 5-15, of the 471.8 ICAP MW of the MOPR Unit Specific Exception requests for the 2024/2025 RPM Base Residual Auction, the MMU agreed with requests for 267.0 MW. Of the 1,288.0 MW offered in the 2024/2025 RPM Base Residual Auction that were subject to MOPR, 1,164.0 MW cleared and 124.0 MW did not clear. There were no unit specific exception requests for MOPR under OATT Attachment DD § 5.14(h-2) for the 2023/2024 RPM Third Incremental Auction. There were no MW subject to MOPR in the 2023/2024 RPM Third Incremental Auction.

Table 5-15 MOPR statistics: RPM auctions held in first quarter, 2023

				ICAP (MW)			UCAP (MW)	
	MOPR Type	Calculation Type	Number of Requests	Requested	MMU Agreed	Offered	Offered	Cleared
2024/2025 Base Residual Auction	OATT Attachment DD § 5.14(h-2)	Unit Specific Exception	4	471.8	267.0	123.0	123.0	123.0
	OATT Attachment DD § 5.14(h-2)	Default	NA	NA	NA	1,213.0	1,165.0	1,041.0
	Total		4	471.8	267.0	1,336.0	1,288.0	1,164.0
2023/2024 Third Incremental Auction	OATT Attachment DD § 5.14(h-2)	Unit Specific Exception	0	0.0	0.0	0.0	0.0	0.0
	OATT Attachment DD § 5.14(h-2)	Default	NA	NA	NA	0.0	0.0	0.0
	Total		0	0.0	0.0	0.0	0.0	0.0

131 See Protest of the Independent Market Monitor for PJM, Docket No. ER21-2582-000 (August 20, 2021); Answer and Motion for Leave to Answer of the Independent Market Monitor for PJM, Docket No. ER21-2582-000 (September 22, 2021).
132 173 FERC ¶ 61,134 (2020).
133 177 FERC ¶ 61,209 (2021).

Replacement Capacity[134]

When a capacity resource is not available for a delivery year, the owner of the capacity resource may purchase replacement capacity. Replacement capacity is the vehicle used to offset any reduction in capacity from a resource which is not available for a delivery year. But the replacement capacity mechanism may also be used to manipulate the market.

Table 5-16 shows the committed and replacement capacity for all capacity resources for June 1 of each year from 2007 through 2024. The 2023 and 2024 numbers are not final.

Sellers of demand resources in RPM auctions disproportionately replace those commitments on a consistent basis compared to sellers of other resource types. External generation and internal generation not in service had high rates of replacement in some years and those are also of concern.

The dynamic that can result is that the speculative DR suppresses prices in the BRA and displaces physical generation assets. Those generation assets then have an incentive to offer at a low price, including offers at zero and below cost, in IAs in order to ensure some capacity market revenue for long lived physical resources which the owners expect to maintain for multiple years. The result is lower IA prices which permit the buyback of the speculative DR at prices below the BRA prices which encourages the greater use of speculative DR.

PJM's sale of capacity in IAs at very low prices, given that PJM announces the MW quantity and the sell offer price in advance of the auctions, further reduces IA prices and increases the incentive of DR sellers to speculate in the BRAs. The MMU recommends that if PJM sells capacity in incremental auctions, PJM should offer the capacity for sale at the BRA clearing price in order to avoid suppressing the IA price below the competitive level. If the PJM sell offer price is not the BRA clearing price, PJM should not reveal its proposed sell offer price or the MW quantity to be sold prior to the auction.

It has been asserted that selling at a high price in the BRA and buying back at a low price in the IA is just a market transaction and therefore does not constitute a problem. But permitting DR to be an option in the BRA rather than requiring DR to be a commitment to provide a physical asset gives DR an unfair advantage and creates a self fulfilling dynamic that incents more of the same behavior. Only DR is permitted to be an option in the BRA. Generation resources must have met physical milestones in order to offer in the BRA. It is not reasonable to permit DR capacity resources to have a different product definition than generation capacity resources. Even if DR is treated as an annual product, this unique treatment as an option makes DR an inferior resource and not a complete substitute for generation resources. The current approach to DR is also inconsistent with the history of the definition of capacity in PJM, which has always been that capacity is physical and unit specific. The current approach to DR effectively makes DR a virtual participant in the PJM Capacity Market. That option should be eliminated.

The definition of demand side resources in PJM capacity markets is flawed in a variety of ways. The current demand side definition should be replaced with a definition that includes demand on the demand side of the market. There are ways to ensure and enhance the vibrancy of demand side without negatively affecting markets for generation. There are other price formation issues in the capacity market that should also be examined and addressed.[135]

134 For more details on replacement capacity, see "Analysis of Replacement Capacity for RPM Commitments: June 1, 2007 to June 1, 2019," <http://www.monitoringanalytics.com/reports/Reports/2019/IMM_Analysis_of_Replacement_Capacity_for_RPM_Commitments_June_1_2007_to_June_1_2019_20190913.pdf> (September 13, 2019).

135 See Monitoring Analytics, LLC, "Analysis of the 2023/2024 RPM Base Residual Auction," <https://www.monitoringanalytics.com/reports/Reports/2022/IMM_Analysis_of_the_20232024_RPM_Base_Residual_Auction_20221028.pdf> (October 28, 2022).

Table 5-16 RPM commitments and replacements for all Capacity Resources: June 1, 2007 to June 1, 2024

	UCAP (MW)					
	RPM Cleared	Adjustments to Cleared	Net Replacements	RPM Commitments	RPM Commitment Shortage	RPM Commitments Less Commitment Shortage
01-Jun-07	129,409.2	0.0	0.0	129,409.2	(8.1)	129,401.1
01-Jun-08	130,629.8	0.0	(766.5)	129,863.3	(246.3)	129,617.0
01-Jun-09	134,030.2	0.0	(2,068.2)	131,962.0	(14.7)	131,947.3
01-Jun-10	134,036.2	0.0	(4,179.0)	129,857.2	(8.8)	129,848.4
01-Jun-11	134,182.6	0.0	(6,717.6)	127,465.0	(79.3)	127,385.7
01-Jun-12	141,295.6	(11.7)	(9,400.6)	131,883.3	(157.2)	131,726.1
01-Jun-13	159,844.5	0.0	(12,235.3)	147,609.2	(65.4)	147,543.8
01-Jun-14	161,214.4	(9.4)	(13,615.9)	147,589.1	(1,208.9)	146,380.2
01-Jun-15	173,845.5	(326.1)	(11,849.4)	161,670.0	(1,822.0)	159,848.0
01-Jun-16	179,773.6	(24.6)	(16,157.5)	163,591.5	(924.4)	162,667.1
01-Jun-17	180,590.5	0.0	(13,982.7)	166,607.8	(625.3)	165,982.5
01-Jun-18	175,996.0	0.0	(12,057.8)	163,938.2	(150.5)	163,787.7
01-Jun-19	177,064.2	0.0	(12,300.3)	164,763.9	(9.3)	164,754.6
01-Jun-20	174,023.8	(335.3)	(10,582.7)	163,105.8	(5.7)	163,100.1
01-Jun-21	174,713.0	0.0	(12,963.3)	161,749.7	(316.9)	161,432.8
01-Jun-22	150,465.2	0.0	(5,576.9)	144,888.3	(1,212.7)	143,675.6
01-Jun-23	150,143.9	0.0	(3,020.0)	147,123.9	0.0	147,123.9
01-Jun-24	147,505.6	0.0	0.0	147,505.6	0.0	147,505.6

Market Performance

Figure 5-5 shows cleared MW weighted average capacity market prices on a delivery year basis including base and incremental auctions for each delivery year, and the weighted average clearing prices by LDA in each Base Residual Auction for the entire history of the PJM capacity markets.

Table 5-17 shows RPM clearing prices for the 2021/2022 through 2024/2025 Delivery Years for all RPM auctions held through the first three months of 2023, and Table 5-18 shows the RPM cleared MW for the 2021/2022 through 2024/2025 Delivery Years for all RPM auctions held through the first three months of 2023. The 2024/2025 RPM Base Residual Auction was conducted in 2022, but the results were not posted until February 27, 2023, due to an issue with the DPL South reliability requirement.

Figure 5-6 shows the RPM cleared MW weighted average prices for each LDA from the 2021/2022 Delivery Year to the current delivery year, and all results for auctions for future delivery years that have been held through the first three months of 2023. A summary of these weighted average prices is given in Table 5-19.

Table 5-20 shows RPM revenue by delivery year for all RPM auctions held through the first three months of 2023 based on the unforced MW cleared and the resource clearing prices. For the 2021/2022 Delivery Year, RPM revenue was $9.4 billion. For the 2022/2023 Delivery Year, RPM revenue was $4.0 billion.

Table 5-21 shows RPM revenue by calendar year for all RPM auctions held through the first three months of 2023. In 2021, RPM revenue was $8.4 billion. In 2022, RPM revenue was $6.2 billion.

Table 5-22 shows the RPM annual charges to load. For the 2020/2021 Delivery Year, annual charges to load were $7.0 billion. For the 2021/2022 Delivery Year, annual charges to load are $9.4 billion.

Table 5-17 Capacity market clearing prices: 2021/2022 through 2024/2025 RPM Auctions

		RPM Clearing Price ($ per MW-day)													
	Product Type	RTO	MAAC	APS	PPL	EMAAC	SWMAAC	DPL South	PSEG	PSEG North	PEPCO	ATSI	COMED	BGE	DUKE
2021/2022 BRA	Capacity Performance	$140.00	$140.00	$140.00	$140.00	$165.73	$140.00	$165.73	$204.29	$204.29	$140.00	$171.33	$195.55	$200.30	$140.00
2021/2022 First Incremental Auction	Capacity Performance	$23.00	$23.00	$23.00	$23.00	$25.00	$23.00	$25.00	$45.00	$219.00	$23.00	$23.00	$23.00	$60.00	$23.00
2021/2022 Second Incremental Auction	Capacity Performance	$10.26	$10.26	$10.26	$10.26	$15.37	$10.26	$15.37	$125.00	$125.00	$10.26	$10.26	$10.26	$70.00	$10.26
2021/2022 Third Incremental Auction	Capacity Performance	$20.55	$20.55	$20.55	$20.55	$26.36	$20.55	$26.36	$31.00	$31.00	$20.55	$20.55	$20.55	$39.00	$20.55
2022/2023 BRA	Capacity Performance	$50.09	$96.42	$50.09	$96.42	$97.75	$95.97	$97.75	$97.75	$97.75	$95.97	$50.09	$67.17	$107.92	$59.38
2022/2023 Third Incremental Auction	Capacity Performance	$50.05	$96.61	$50.05	$96.61	$97.93	$96.15	$97.93	$97.93	$97.93	$96.15	$50.05	$66.23	$108.22	$59.75
2023/2024 BRA	Capacity Performance	$34.13	$49.49	$34.13	$49.49	$49.49	$49.49	$69.95	$49.49	$49.49	$49.49	$34.13	$34.13	$69.95	$34.13
2023/2024 Third Incremental Auction	Capacity Performance	$37.53	$49.49	$37.53	$49.49	$146.03	$49.49	$146.03	$146.03	$146.03	$49.49	$37.53	$37.53	$79.03	$37.53
2024/2025 BRA	Capacity Performance	$28.92	$49.49	$28.92	$49.49	$54.95	$49.49	$90.64	$54.95	$54.95	$49.49	$28.92	$28.92	$73.00	$28.92

Table 5-18 Capacity market cleared MW: 2021/2022 through 2024/2025 RPM Auctions[136]

		UCAP (MW)													
Delivery Year	Auction	RTO	MAAC	APS	PPL	EMAAC	DPL South	PSEG	PSEG North	PEPCO	ATSI	COMED	BGE	DUKE	TOTAL
2021/2022	BASE	52,896.5	12,565.1	10,136.1	15,368.6	19,857.3	1,673.8	4,667.2	3,134.1	6,546.1	8,010.5	22,358.1	3,667.8	2,746.1	163,627.3
2021/2022	FIRST	194.1	200.4	45.9	27.2	119.0	15.3	18.3	79.1	207.9	739.3	360.4	48.7	87.6	2,143.2
2021/2022	SECOND	1,242.5	335.8	30.3	55.4	129.9	39.3	97.0	98.1	75.7	1,216.8	205.9	115.5	65.3	3,707.5
2021/2022	THIRD	1,638.4	168.7	231.6	127.8	911.0	18.3	227.7	244.8	67.2	942.7	221.7	275.9	159.2	5,235.0
2022/2023	BASE	37,732.2	12,804.7	10,147.4	14,118.7	23,658.8	1,305.3	1,914.3	2,531.1	3,621.8	10,550.7	19,223.7	4,750.9	2,117.7	144,477.3
2022/2023	THIRD	1,099.0	338.9	84.2	105.7	572.2	9.4	244.3	402.0	27.4	358.0	2,292.3	409.7	44.8	5,987.9
2023/2024	BASE	36,908.8	10,098.5	8,145.5	14,352.7	22,942.3	1,383.1	2,497.1	3,344.9	3,521.8	9,535.9	25,368.9	5,001.0	1,966.4	145,066.9
2023/2024	THIRD	315.7	1,786.4	395.0	79.3	671.0	24.2	32.4	43.8	15.3	355.8	1,050.0	240.0	68.4	5,077.0
2024/2025	BASE	37,406.8	10,855.5	8,874.0	14,184.9	23,151.1	1,444.7	2,665.3	3,494.3	3,433.8	9,720.6	25,156.1	5,056.5	2,062.1	147,505.6

136 The MW values in this table refer to rest of LDA or RTO values, which are net of nested LDA values.

Table 5-19 Weighted average clearing prices by zone: 2021/2022 through 2024/2025

	Weighted Average Clearing Price ($ per MW-day)			
LDA	2021/2022	2022/2023	2023/2024	2024/2025
RTO				
AEP	$133.84	$49.25	$34.13	$28.92
APS	$133.84	$49.25	$34.13	$28.92
ATSI	$142.59	$48.89	$34.13	$28.92
Cleveland	$90.81	$49.41	$34.13	$28.92
COMED	$189.54	$63.70	$34.13	$28.92
DAY	$132.69	$49.16	$34.13	$28.92
DUKE	$127.66	$70.57	$34.13	$96.17
DUQ	$133.84	$49.25	$34.13	$28.92
DOM	$133.84	$49.25	$34.13	$28.92
EKPC	$133.84	$49.25	$34.13	$28.92
MAAC				
EMAAC				
ACEC	$158.72	$96.30	$49.49	$54.94
DPL	$158.72	$96.30	$49.49	$54.94
DPL South	$159.65	$97.41	$69.95	$90.64
JCPLC	$158.72	$96.30	$49.49	$54.94
PECO	$158.72	$96.30	$49.49	$54.94
PSEG	$184.82	$90.67	$49.48	$54.77
PSEG North	$190.48	$89.21	$49.49	$54.82
REC	$158.72	$96.30	$49.49	$54.94
SWMAAC				
BGE	$174.43	$119.73	$69.94	$72.99
PEPCO	$133.37	$94.74	$49.46	$49.44
WMAAC				
MEC	$134.56	$94.49	$49.49	$49.49
PE	$134.56	$94.49	$49.49	$49.49
PPL	$138.51	$95.29	$49.49	$49.48

Table 5-20 RPM revenue by delivery year: 2007/2008 through 2024/2025[137]

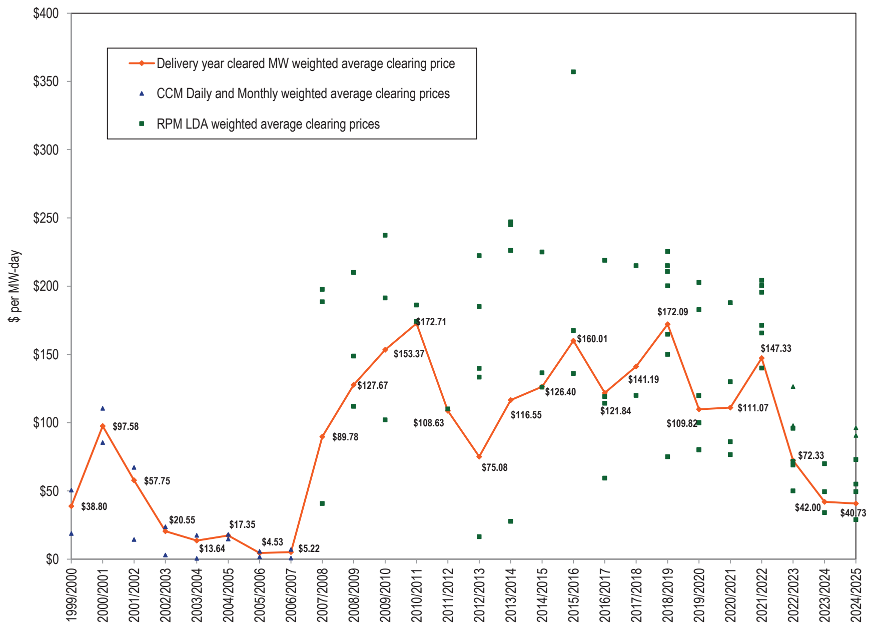
Delivery Year	Weighted Average RPM Price ($ per MW-day)	Weighted Average Cleared UCAP (MW)	Days	RPM Revenue
2007/2008	$89.78	129,409.2	366	$4,252,287,381
2008/2009	$127.67	130,629.8	365	$6,087,147,586
2009/2010	$153.37	134,030.2	365	$7,503,218,157
2010/2011	$172.71	134,036.2	365	$8,449,652,496
2011/2012	$108.63	134,182.6	366	$5,335,087,023
2012/2013	$75.08	141,283.9	365	$3,871,714,635
2013/2014	$116.55	159,844.5	365	$6,799,778,047
2014/2015	$126.40	161,205.0	365	$7,437,267,646
2015/2016	$160.01	173,519.4	366	$10,161,726,902
2016/2017	$121.84	179,749.0	365	$7,993,888,695
2017/2018	$141.19	180,590.5	365	$9,306,676,719
2018/2019	$172.09	175,996.0	365	$11,054,943,851
2019/2020	$109.82	177,064.2	366	$7,116,815,360
2020/2021	$111.07	173,688.5	365	$7,041,524,517
2021/2022	$147.33	174,713.0	365	$9,395,567,946
2022/2023	$72.33	150,465.2	365	$3,972,428,671
2023/2024	$42.00	150,143.9	366	$2,308,241,974
2024/2025	$40.73	147,505.6	365	$2,192,828,381

Table 5-21 RPM revenue by calendar year: 2007 through 2025[138]

Year	Weighted Average RPM Price ($ per MW-day)	Weighted Average Cleared UCAP (MW)	Effective Days	RPM Revenue
2007	$89.78	75,665.5	214	$2,486,310,108
2008	$111.93	130,332.1	366	$5,334,880,241
2009	$142.74	132,623.5	365	$6,917,391,702
2010	$164.71	134,033.7	365	$8,058,113,907
2011	$135.14	133,907.1	365	$6,615,032,130
2012	$89.01	138,561.1	366	$4,485,656,150
2013	$99.39	152,166.0	365	$5,588,442,225
2014	$122.32	160,642.2	365	$7,173,539,072
2015	$146.10	168,147.0	365	$9,018,343,604
2016	$137.69	177,449.8	366	$8,906,998,628
2017	$133.19	180,242.4	365	$8,763,578,112
2018	$159.31	177,896.7	365	$10,331,688,133
2019	$135.58	176,338.6	365	$8,734,613,179
2020	$110.55	175,368.7	366	$7,084,072,778
2021	$132.33	174,289.2	365	$8,421,703,404
2022	$103.36	160,496.5	365	$6,215,973,960
2023	$54.55	150,036.3	365	$2,993,016,120
2024	$41.26	148,837.6	366	$2,244,272,436
2025	$40.73	61,022.9	151	$907,170,097

137 The results for the ATSI Integration Auctions are not included in this table.
138 The results for the ATSI Integration Auctions are not included in this table.

Figure 5-5 History of capacity prices: 1999/2000 through 2024/2025[139]



139 The 1999/2000 through 2006/2007 capacity prices are CCM combined market, weighted average prices. The 2007/2008 through 2024/2025 capacity prices are RPM weighted average prices. The CCM data points plotted are cleared MW weighted average prices for the daily and monthly markets by delivery year. The RPM data points plotted are RPM LDA clearing prices. For the 2014/2015 and subsequent delivery years, only the prices for Annual Resources or Capacity Performance Resources are plotted.

Figure 5-6 Map of RPM capacity prices: 2021/2022 through 2024/2025

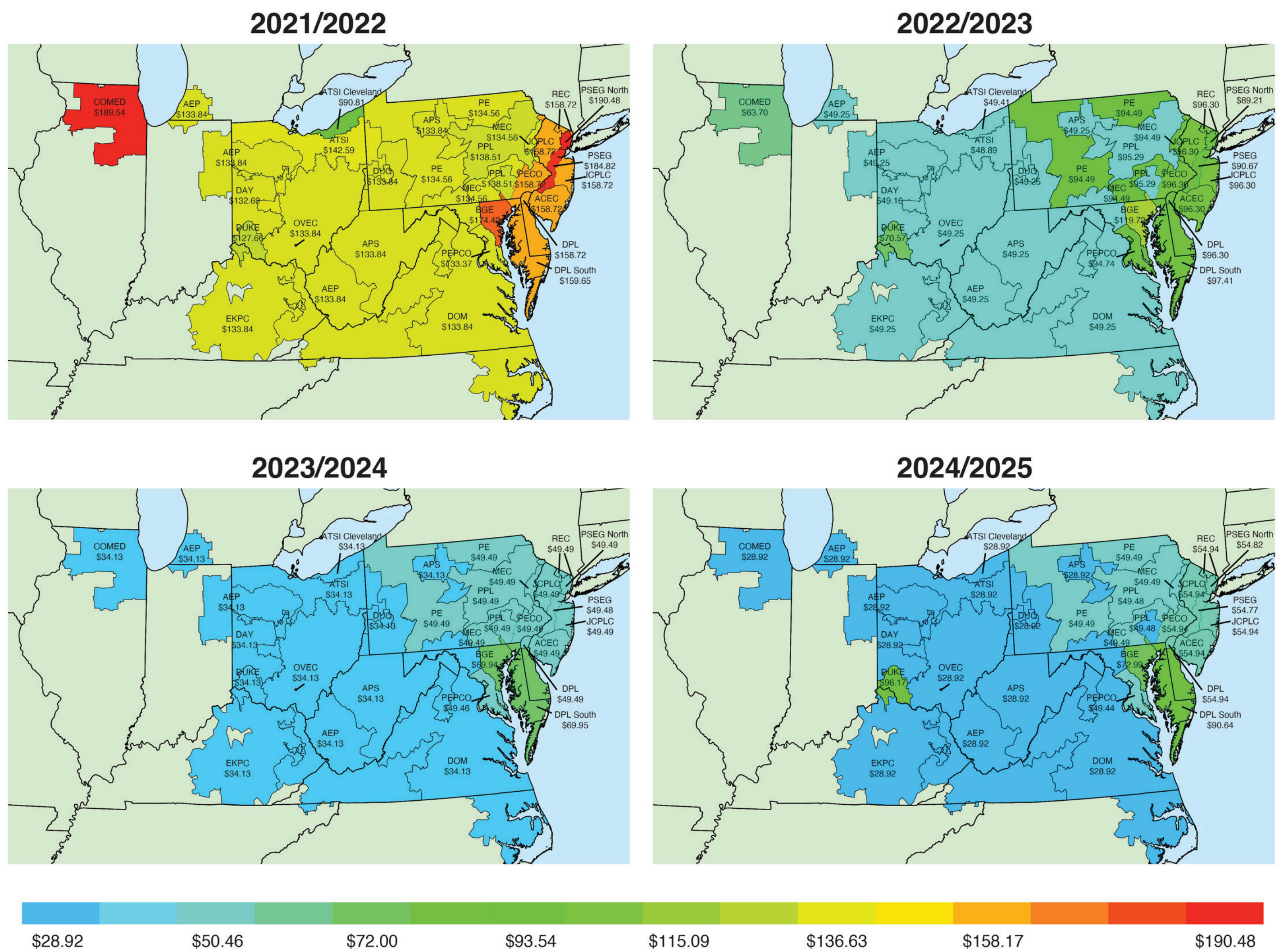


Table 5-22 RPM cost to load: 2021/2022 through 2024/2025 RPM Auctions[140 141 142]

	Net Load Price ($ per MW-day)	UCAP Obligation (MW)	Annual Charges
2021/2022			
Rest of RTO	$142.16	82,768.3	$4,294,838,410
Rest of EMAAC	$164.73	23,719.9	$1,426,178,211
ATSI	$160.21	13,995.4	$818,411,597
BGE	$163.50	7,491.2	$447,049,048
COMED	$198.43	22,721.2	$1,645,630,168
PSEG	$188.46	10,987.4	$755,803,998
Total		161,683.4	$9,387,911,433
2022/2023			
Rest of RTO	$50.05	50,750.7	$927,101,691
EMAAC	$97.93	35,388.1	$1,264,867,389
WMAAC	$96.61	15,072.2	$531,498,382
BGE	$108.22	7,457.7	$294,575,131
COMED	$66.23	24,064.5	$581,774,443
DEOK	$59.75	5,090.6	$111,011,442
PEPCO	$96.15	6,870.5	$241,111,291
Total		144,694.3	$3,951,939,768
2023/2024			
Rest of RTO	$34.18	78,896.5	$986,982,057
EMAAC	$50.96	30,972.7	$577,657,195
WMAAC	$49.58	22,401.9	$406,535,572
DPL	$57.19	4,375.0	$91,582,753
BGE	$59.38	7,496.6	$162,936,916
Total		144,142.8	$2,225,694,492
2024/2025			
Rest of RTO	$28.99	76,450.4	$809,031,213
EMAAC	$54.50	31,332.0	$623,235,448
WMAAC	$49.68	22,302.1	$404,400,620
DPL	$66.07	4,607.4	$111,117,775
BGE	$59.83	7,556.5	$165,020,181
DEOK	$57.50	5,230.4	$109,776,921
Total		147,478.9	$2,222,582,158

140 The RPM annual charges are calculated using the rounded, net load prices as posted in the PJM RPM auction results.
141 There is no separate obligation for DPL South as the DPL South LDA is completely contained within the DPL Zone. There is no separate obligation for PSEG North as the PSEG North LDA is completely contained within the PSEG Zone. There is no separate obligation for ATSI Cleveland as the ATSI Cleveland LDA is completely contained within the ATSI Zone.
142 The net load prices and obligation MW for 2023/2024 and 2024/2025 are not final.

FRR

The states have authority over their generation resources and can choose to remain in PJM capacity markets or to create FRR entities. The existing FRR approach remains an option for utilities with regulated revenues based on cost of service rates, including both privately and publicly owned (including public power entities and electric cooperatives) utilities. Such regulated utilities have had and continue to have the ability to opt out of the capacity market and provide their own capacity. The existing FRR rules were created in 2007 primarily for the specific circumstances of AEP as part of the original RPM capacity market design settlement. The MMU recommends that the FRR rules be revised and updated to ensure that the rules reflect current market realities and that FRR entities do not unfairly take advantage of those customers paying for capacity in the PJM Capacity Market.

The MMU has prepared reports with analysis of the potential impacts on states pursuing the FRR option. In separate reports for Illinois, Maryland, New Jersey, Ohio, Virginia, and the District of Columbia, the cost impacts of the state choosing the FRR option are computed under different FRR capacity price assumptions and different assumptions regarding the composition of the FRR service area.[143 144 145 146 147 148] The reports showed that the FRR approach is likely to lead to significant increases in payments by customers if it were to replace participation in the PJM markets. The impact on the remaining PJM capacity market footprint is also computed for each scenario. In all but a few scenarios the MMU finds that the FRR leads to higher costs for load included in the FRR service area. In all scenarios the MMU finds that prices in what remains of the PJM Capacity Market would be significantly lower.

143 See Monitoring Analytics, LLC, "Potential Impacts of the Creation of a ComEd FRR," <http://www.monitoringanalytics.com/reports/Reports/2019/IMM_Potential_Impacts_of_the_Creation_of_a_ComEd_FRR_20191218.pdf> (December 18, 2020).
144 See Monitoring Analytics, LLC, "Potential Impacts of the Creation of Maryland FRRs," <http://www.monitoringanalytics.com/reports/Reports/2020/IMM_Potential_Impacts_of_the_Creation_of_Maryland_FRRs_20200416.pdf> (April 16, 2020).
145 See Monitoring Analytics, LLC, "Potential Impacts of the Creation of New Jersey FRRs," <http://www.monitoringanalytics.com/reports/Reports/2020/IMM_Potential_Impacts_of_the_Creation_of_New_Jersey_FRRS_20200513.pdf> (May 13, 2020).
146 *In the Matter of the Investigation of Resource Adequacy Alternatives*, New Jersey Board of Public Utilities, Docket No. EO20030203. Monitoring Analytics, LLC Comments, <http://www.monitoringanalytics.com/filings/2020/IMM_Comments_Docket_No_EO20030203_20200520.pdf> (May 20, 2020). Monitoring Analytics, LLC, Reply Comments <http://www.monitoringanalytics.com/filings/2020/IMM_Reply_Comments_Docket_No_EO20030203_20200624.pdf>. (June 24, 2020). Monitoring Analytics, Answer to Exelon and PSEG, <http://www.monitoringanalytics.com/filings/2020/IMM_Answer_to_Exelon_PSEG_Docket_No_EO20030203_20200715.pdf> (July 15, 2020).
147 See Monitoring Analytics, LLC, "Potential Impacts of the Creation of Ohio FRRs," <http://www.monitoringanalytics.com/reports/Reports/2020/IMM_Potential_Impacts_of_the_Creation_of%20Ohio_FRRs_20200717.pdf> (July 17, 2020).
148 See Monitoring Analytics, LLC, "Potential Impacts of the Creation of Virginia FRRs," <https://www.monitoringanalytics.com/reports/Reports/2021/IMM_VA_FRR_Report_20210518.pdf> (May 18, 2021).

Both FERC and the states have significant and overlapping authority affecting wholesale power markets. While the FERC MOPR approach was designed to ensure that subsidies did not affect the wholesale power markets, the states have ultimate authority over the generation choices made in the states. The FRR explorations by multiple states illustrated a possible path forward. Under that path, the FERC regulated markets would be unaffected by subsidies but many states would withdraw from the FERC regulated markets and create higher cost nonmarket solutions rather than be limited by MOPR. That would not be an efficient outcome and would not serve the interests of customers or generators.

With the elimination of the current MOPR rules, the capacity market design must accommodate the choices made by states to subsidize renewable resources in a way that maximizes the role of competition to ensure that customers pay the lowest amount possible, consistent with state goals and the costs of providing the desired resources. Such an approach can take several forms, but none require the dismantling of the PJM capacity market design. The PJM capacity market design can adapt to a wide range of state supported resources and state programs. As a simple starting point, states can continue to support selected resources using a range of payment structures and those resources could participate in the capacity auctions. As a broader and more comprehensive option, PJM could create a central PJM RECs market to facilitate the competitive sale and purchase of RECs.

CRF Issue[149]

As a result of the significant changes to the federal tax code in December 2017, the capital recovery factor (CRF) tables in PJM OATT Attachment DD § 6.8(a) and Schedule 6A were not correct. These tables should have been updated in 2018. Correct CRFs ensure that offer caps and offer floors in the capacity market are correct. On May 4, 2021, PJM filed updates to the OATT under FPA Section 205.[150] In the filing, PJM proposed new CRFs based on the new tax law and new financial assumptions. The new financial assumptions are identical to the assumptions used in the PJM quadrennial review for the calculation of the cost of new entry (CONE) for the PJM reference resource. The MMU, in comments to the Commission, asked that the following formula be included in the tariff as an efficient alternative to use of tables which require updates whenever tax laws or financial assumptions change:[151] [152]

$$\mathrm{CRF} = \frac{r(1+r)^N\left[1 - \frac{sB}{\sqrt{1+r}} - s(1-B)\sqrt{1+r}\,\sum_{\mathrm{j}=1}^{\mathrm{L}} \frac{\mathrm{m_j}}{(1+\mathrm{r})^{\mathrm{j}}}\right]}{(1-s)\sqrt{1+\mathrm{r}}\,[(1+r)^N - 1]}$$

The MMU also proposed that PJM discontinue the practice of using an average state tax rate in the CRF calculation. The CRF formula allows for the quick and efficient calculation of a unit's CRF using the state tax rate that is applicable to a specific unit.

FERC accepted PJM's filing but also required that the CRF formula be included in the tariff.[153] FERC rejected the MMU's unit specific state tax recommendation. Going forward, PJM will post the CRFs on their website. Table 5-24 shows the CRFs that are currently posted. The values in Table 5-24 were calculated using the formula above and the financial assumptions in Table 5-25. Bonus depreciation assumptions vary by delivery year with 100 percent bonus depreciation assumed in the 2022/2023 Delivery Year. The bonus depreciation in each subsequent delivery year is reduced by 20 percent.

Table 5-23 Variable descriptions for the CRF formula

Formula Symbol	Description
r	After tax weighted average cost of capital (ATWACC)
s	Effective tax rate
B	Bonus depreciation percent
N	Cost Recovery Period (years)
L	Lesser of N or 16 (years)
mj	Modified Accelerated Cost Recovery System (MACRS) depreciation factor for year j = 1, ..., 16

149 See related filing on CRF issue in black start: Comments of the Independent Market Monitor for PJM, Docket No. ER21-1635 (April 28, 2021).

150 "Revisions to Capital Recovery Factor for Avoidable Project Investment Cost Determinations and Request for Waiver of Sixty-Day Notice Requirement," PJM Interconnection L.L.C., Docket No. ER21-1844-000 (May 4, 2021).

151 See "Comments of the Independent Market Monitor for PJM," Docket No. ER21-1844-000 (May 25, 2021).

152 The formula was first introduced in a related Section 205 filing regarding CRFs for black start service. See "Comments of the Independent Market Monitor for PJM" (April 28, 2021) and "Answer and Motion to Answer of the Independent Market Monitor for PJM" (May 19, 2021) in Docket No. ER21-1635-000.

153 Order 176 FERC ¶61,003 (July 2, 2021).

The MMU supports the changes to the tariff to correct the application of CRF to the capacity market but there are still unresolved issues. The tariff revisions lack clarity about how CRF values will be determined in the future and to which projects they apply, and lack clarity about how CRF values would be applied to APIR for project costs that are currently being recovered. For example, Table 5-24, which is identical to the table posted by PJM, includes CRF values for projects that go into service for four identified delivery years but fails to note that these CRF values for a later delivery year would not apply for investments made in prior delivery years that will still be in service in the later delivery year.[154] For example, a project that can use the depreciation provisions relevant for the 2023/2024 Delivery Year uses the depreciation provisions once and those provisions affect the project's CRF for its entire life, regardless of the CRF values in the table for subsequent delivery years. However, changes in the tax rate apply each year and if the tax rate changes the applicable CRF values would change for all projects, regardless of vintage. As a result, the CRF values in Table 5-24 for delivery years after 2022/2023 would not apply to the calculation of APIR values for projects that go into service for the 2022/2023 Delivery Year. A similar issue exist for projects that were assigned a CRF under the previous tariff rules. The change in the tax rate should be reflected in the CRF going forward. PJM does not plan to do this and the Commission indicated that the issue is "beyond the scope" of the PJM filing.[155]

Table 5-24 Levelized CRF values: Delivery Year 2022/2023 through Delivery Year 2025/2026

Age of Existing Units (Years)	Remaining Life of Plant	Levelized CRF 2022/2023	Levelized CRF 2023/2024	Levelized CRF 2024/2025	Levelized CRF 2025/2026
1 to 5	30	0.088	0.091	0.094	0.096
6 to 10	25	0.093	0.096	0.098	0.101
11 to 15	20	0.101	0.104	0.107	0.110
16 to 20	15	0.116	0.119	0.122	0.126
21 to 25	10	0.147	0.152	0.158	0.164
25 Plus	5	0.246	0.258	0.271	0.283
Mandatory CapEx	4	0.296	0.312	0.328	0.345
40 Plus Alternative	1	1.100	1.100	1.100	1.100

154 See "Capital Recovery Factors ("CRF") for Avoidable Project Investment Cost ("APIR") Determinations," <https://pjm.com/-/media/markets-ops/rpm/rpm-auction-info/crf-values-for-apir-determination.ashx>.
155 Order 176 FERC ¶61,003 (July 2, 2021) at 28.

Table 5-25 Financial parameter and tax rate assumptions for CRF calculations

Financial Parameter	Parameter Value
Equity Funding Percent	45.000%
Debt Funding Percent	55.000%
Equity Rate	13.000%
Debt Interest Rate	6.000%
Federal Tax Rate	21.000%
State Tax Rate	9.300%
Effective Tax Rate	28.347%
After tax Weighted Average Cost of Capital	8.215%

Timing of Unit Retirements

Generation owners that want to deactivate a unit, either to mothball or permanently retire, must provide notice to PJM and the MMU prior to the proposed deactivation date. Prior to September 2022, generation owners were required to provide deactivation notices at least 90 days before the proposed deactivation date. Beginning in September 2022, PJM and the MMU began reviewing deactivation requests quarterly, and the desired deactivation date is now based on the quarter the request was submitted (Table 5-26).

Table 5-26 Earliest deactivation dates allowed based on quarterly submission

Date Request Submitted	Earliest Deactivation Date Permitted
January 1 to March 31	July 1
April 1 to June 30	October 1
July 1 to September 30	January 1 (following calendar year)
October 1 to December 31	April 1 (following clendar year)

Generation owners seeking a capacity market must offer exemption for a delivery year must submit their deactivation request no later than the December 1 preceding the Base Residual Auction or 120 days before the start of an Incremental Auction for that delivery year.[156] If no reliability issues are found during PJM's analysis of the retirement's impact on the transmission system, and the MMU finds no market power issues associated with the proposed deactivation, the unit may deactivate at any time thereafter.[157]

Table 5-27 shows the timing of actual deactivation dates and the initially requested deactivation date, for all deactivation requests submitted from

156 OATT Attachment DD § 6.6(g).
157 OATT Part V §113.

January 2018 through March 2023. Of the 146 deactivation requests submitted, 26 units (17.8 percent) deactivated an average of 183 days earlier than their initially requested date; 22 units (15.1 percent) deactivated an average of 81 days later than the originally requested deactivation date; and 56 units (38.4 percent) deactivated on their initially requested date. Fifteen (10.3 percent) of the unit deactivations were cancelled an average of 351 days before their scheduled deactivation date, and 27 (15.7 percent) of the unit deactivations have not yet reached their target retirement date. Table 5-28 shows this information broken out by fuel types.

Table 5-27 Timing of actual unit deactivations compared to requested deactivation date: Requests submitted January 2018 through March 2023

Status	Number of Units	Percent	Average Days Deviation from Originally Requested Date
Early	26	17.8%	(183)
Late	22	15.1%	81
On time	56	38.4%	0
Cancelled	15	10.3%	(351)
Pending	27	18.5%	-
Total	146	100.0%	-

Table 5-28 Timing of actual unit deactivations compared to requested deactivation date by fuel type: Requests submitted January 2018 through December 2022

Fuel Type	Status	Number of Units	Percent	Average Days Deviation from Originally Requested Date
Biomass	Early	2	66.7%	(4)
	Late	0	0.0%	-
	On time	0	0.0%	-
	Cancelled	0	0.0%	-
	Pending	1	33.3%	-
	Total	3	100.0%	-
Coal	Early	11	26.8%	(219)
	Late	8	19.5%	87
	On time	12	29.3%	0
	Cancelled	2	4.9%	(832)
	Pending	8	19.5%	-
	Total	41	100.0%	-
Diesel	Early	0	0.0%	-
	Late	0	0.0%	-
	On time	0	0.0%	-
	Cancelled	0	0.0%	-
	Pending	4	100.0%	-
	Total	4	100.0%	-
Methane	Early	4	16.7%	(107)
	Late	7	29.2%	71
	On time	10	41.7%	0
	Cancelled	2	8.3%	(190)
	Pending	1	4.2%	-
	Total	24	100.0%	-
Natural Gas	Early	3	13.6%	(262)
	Late	3	13.6%	5
	On time	8	36.4%	0
	Cancelled	0	0.0%	-
	Pending	8	36.4%	-
	Total	22	100.0%	-
Nuclear	Early	0	0.0%	-
	Late	0	0.0%	-
	On time	0	0.0%	-
	Cancelled	10	100.0%	(312)
	Pending	0	0.0%	-
	Total	10	100.0%	-
Oil	Early	3	8.6%	(218)
	Late	4	11.4%	146
	On time	22	62.9%	0
	Cancelled	1	2.9%	(105)
	Pending	5	14.3%	-
	Total	35	100.0%	-
Solid Waste	Early	0	0.0%	-
	Late	0	0.0%	-
	On time	1	100.0%	0
	Cancelled	0	0.0%	-
	Pending	0	0.0%	-
	Total	1	100.0%	-
Storage	Early	3	50.0%	-
	Late	0	0.0%	-
	On time	3	50.0%	0
	Cancelled	0	0.0%	-
	Pending	0	0.0%	-
	Total	6	100.0%	-

Part V Reliability Service

PJM must make out of market payments to units that want to retire (deactivate) but that PJM requires to remain in service, for limited operation, for a defined period because the unit is needed for reliability.[158] This provision has been known as Reliability Must Run (RMR) service but RMR is not defined in the PJM tariff. Here the term Part V reliability service is used. The need to retain uneconomic units in service reflects a flawed market design and/or planning process problems. If a unit is needed for reliability, the market should reflect a locational value consistent with that need which would result in the unit remaining in service or being replaced by a competitor unit. The planning process should evaluate the impact of the loss of units at risk and determine in advance whether transmission upgrades are required.[159] It is essential that the deactivation provisions of the tariff be evaluated and modified. It is also essential that PJM look forward and attempt to plan for foreseeable unit retirements, whether for economic or regulatory reasons.

When notified of an intended deactivation, the MMU performs a market power study to ensure that the deactivation is economic, not an exercise of market power through withholding, and consistent with competition.[160] PJM performs a system study to determine whether the system can accommodate the deactivation on the desired date, and if not, when it could.[161] If PJM determines that it needs a unit for a period beyond the intended deactivation date, PJM will request a unit to remain in service, generally only as an option in the event the unit is needed for reliability.[162] The PJM market rules do not require an owner to remain in service, but owners must provide advance notice of a proposed deactivation (See Table 5-26).[163] The owner of a generation capacity resource must provide notice of a proposed deactivation in order to avoid a requirement to offer in RPM auctions.[164] In order to avoid submitting an offer for a unit in the next three-year forward RPM base residual auction, an owner must show "a documented plan in place to retire the resource," including a notice of deactivation filed with PJM, 120 days prior to such auction.[165]

Under the current rules, a unit remaining in service at PJM's request can recover its costs of continuing to operate under either the deactivation avoidable cost rate (DACR), which is a formula rate, or the cost of service recovery rate. The deactivation avoidable cost rate is designed to permit the recovery of the costs of the unit's "continued operation," termed "avoidable costs," plus an incentive adder.[166] Avoidable costs are defined to mean "incremental expenses directly required for the operation of a generating unit."[167] The incentives escalate for each year of service (first year, 10 percent; second year, 20 percent; third year, 35 percent; fourth year, 50 percent).[168] The rules provide terms for the repayment of project investment by owners of units that choose to keep units in service after the defined period ends.[169] Project investment is capped at $2 million, above which FERC approval is required.[170] The cost of service rate is designed to permit the recovery of the unit's "cost of service rate to recover the entire cost of operating the generating unit" if the generation owner files a separate rate schedule at FERC.[171]

Table 5-29 shows units that have provided Part V reliability service to PJM, including the Indian River 4 unit, which began providing RMR service on June 1, 2022.

158 OATT Part V §114.
159 *See, e.g.*, 140 FERC ¶ 61,237 at P 36 (2012) ("The evaluation of alternatives to an SSR designation is an important step that deserves the full consideration of MISO and its stakeholders to ensure that SSR Agreements are used only as a 'limited, last-resort measure.'"); 118 FERC ¶ 61,243 at P 41 (2007) ("the market participants that pay for the agreements pay out-of-market prices for the service provided under the RMR agreements, which broadly hinders market development and performance.[footnote omitted] As a result of these factors, we have concluded that RMR agreements should be used as a last resort."); 110 FERC ¶ 61,315 at P 40 (2005) ("The Commission has stated on several occasions that it shares the concerns . . . that RMR agreements not proliferate as an alternative pricing option for generators, and that they are used strictly as a last resort so that units needed for reliability receive reasonable compensation.").
160 OATT § 113.2; OATT Attachment M § IV.1.
161 OATT § 113.2.
162 *Id.*
163 OATT § 113.1.
164 OATT Attachment DD § 6.6(g).
165 *Id.*
166 OATT § 114 (Deactivation Avoidable Credit = ((Deactivation Avoidable Cost Rate + Applicable Adder) * MW capability of the unit * Number of days in the month) – Actual Net Revenues).
167 OATT § 115.
168 *Id.*
169 OATT § 118.
170 OATT §§ 115, 117.
171 OATT § 119.

Table 5-29 Part V reliability service summary

Unit Names	Owner	ICAP (MW)	Cost Recovery Method	Docket Numbers	Start of Term	End of Term
Indian River 4	NRG Power Marketing LLC	411.9	Cost of Service Recovery Rate	ER22-1539	01-Jun-22	31-Dec-26
B.L. England 2	RC Cape May Holdings, LLC	150.0	Cost of Service Recovery Rate	ER17-1083	01-May-17	30-Apr-19
Yorktown 1	Dominion Virginia Power	159.0	Deactivation Avoidable Cost Rate	ER17-750	06-Jan-17	08-Mar-19
Yorktown 2	Dominion Virginia Power	164.0	Deactivation Avoidable Cost Rate	ER17-750	06-Jan-17	08-Mar-19
B.L. England 3	RC Cape May Holdings, LLC	148.0	Cost of Service Recovery Rate	ER17-1083	01-May-17	24-Jan-18
Ashtabula	FirstEnergy Service Company	210.0	Deactivation Avoidable Cost Rate	ER12-2710	01-Sep-12	11-Apr-15
Eastlake 1	FirstEnergy Service Company	109.0	Deactivation Avoidable Cost Rate	ER12-2710	01-Sep-12	15-Sep-14
Eastlake 2	FirstEnergy Service Company	109.0	Deactivation Avoidable Cost Rate	ER12-2710	01-Sep-12	15-Sep-14
Eastlake 3	FirstEnergy Service Company	109.0	Deactivation Avoidable Cost Rate	ER12-2710	01-Sep-12	15-Sep-14
Lakeshore	FirstEnergy Service Company	190.0	Deactivation Avoidable Cost Rate	ER12-2710	01-Sep-12	15-Sep-14
Elrama 4	GenOn Power Midwest, LP	171.0	Cost of Service Recovery Rate	ER12-1901	01-Jun-12	01-Oct-12
Niles 1	GenOn Power Midwest, LP	109.0	Cost of Service Recovery Rate	ER12-1901	01-Jun-12	01-Oct-12
Cromby 2 and Diesel	Exelon Generation Company, LLC	203.7	Cost of Service Recovery Rate	ER10-1418	01-Jun-11	01-Jan-12
Eddystone 2	Exelon Generation Company, LLC	309.0	Cost of Service Recovery Rate	ER10-1418	01-Jun-11	01-Jun-12
Brunot Island CT2A, CT2B, CT3 and CC4	Orion Power MidWest, L.P.	244.0	Cost of Service Recovery Rate	ER06-993	16-May-06	05-Jul-07
Hudson 1	PSEG Energy Resources & Trade LLC and PSEG Fossil LLC	355.0	Cost of Service Recovery Rate	ER05-644, ER11-2688	25-Feb-05	08-Dec-11
Sewaren 1-4	PSEG Energy Resources & Trade LLC and PSEG Fossil LLC	453.0	Cost of Service Recovery Rate	ER05-644	25-Feb-05	01-Sep-08

Only two of eight owners have used the deactivation avoidable cost rate approach. The other six owners used the cost of service recovery rate.

In each of the cost of service recovery rate filings for Part V reliability service, the scope of recovery permitted under the cost of service approach defined in Section 119 has been a significant issue. Owners have sought to recover fixed costs, incurred prior to the noticed deactivation date, in addition to the cost of operating the generating unit. Owners have cited the cost of service reference to mean that the unit is entitled to file to recover costs that it was unable to recover in the competitive markets, in addition to recovery of costs of actually providing the Part V reliability service.

The cost of service recovery rate approach has been interpreted by the companies using that approach to allow the company to develop the type of rate case filing used by regulated utilities, using a test year with adjustments, to establish a rate base including investment in the existing plant and new investment necessary to remain in service and to earn a return on that rate base and receive depreciation of that rate base, plus guarantee recovery of estimated operation and maintenance expenses. Companies developing the cost of service recovery rate have ignored the tariff's limitation to the costs of operating the unit during the Part V reliability service period and have included costs incurred prior to the decision to deactivate and costs associated with closing the unit that would have been incurred regardless of the Part V reliability service period.[172] In some cases, the filing included costs that already had been written off, or impaired, on the company's public books.[173] [174] The requested cost of service recovery rates substantially exceed the actual costs of operating to provide the reliability required by PJM.

Because such units are needed by PJM for reliability reasons, and the provision of the service is voluntary in PJM, owners of units that PJM needs to remain in service after the desired retirement date have significant market power in establishing the terms of this reliability service.

172 See, e.g., FERC Dockets Nos. ER10-1418-000, ER12-1901-000 and ER17-1083-000.
173 See GenOn Filing, Docket No. ER12-1901-000 (May 31, 2012) at Exh. No. GPM-1 at 9:16–21.
174 See NRG Filing, Docket No. ER22- 1539-000 (April 1, 2022)

This reliability service should be provided to PJM customers at reasonable rates, which reflect the riskless nature of providing such service to owners, the reliability need for such service and the opportunity for owners to be guaranteed recovery of 100 percent of the actual costs required to operate to provide the service.

The MMU recommends elimination of the cost of service recovery rate in OATT Section 119, that this service should be provided under the deactivation avoidable cost rate in Part V, and that the investment cap under the avoidable cost rate option be eliminated.

The MMU also recommends, based in part on its experience with application of the deactivation avoidable cost rate and proceedings filed under Section 119, the following improvements to the DACR provisions:

- Revise the applicable adders in Section 114 to be 15 percent for the second year of Part V reliability service and 20 percent for the provision of Part V reliability service in excess of two years.
- Add true up provisions that ensure that the service provider is reimbursed for, and consumers pay for, the actual incremental costs associated with the service, plus the applicable adder.
- Eliminate the $2 million cap on project investment expenditures.
- Clearly distinguish operating expenses and project investment costs.
- Clarify the tariff language in Section 118 regarding the refund of project investment in the event the unit continues operation beyond the defined term of service.

Generator Performance

Generator performance results from the interaction between the physical characteristics of the units and the level of expenditures made to maintain the capability of the units, which in turn is a function of incentives from energy, ancillary services and capacity markets. Generator performance indices include those based on total hours in a period (generator performance factors) and those based on hours when units are needed to operate by the system operator (generator forced outage rates).

Capacity Factor

Capacity factor measures the actual output of a power plant over a period of time compared to the potential output of the unit had it been running at full nameplate capacity for every hour during that period. Table 5-30 shows the capacity factors by unit type for the first three months of 2022 and 2023. In the first three months of 2023, nuclear units had a capacity factor of 96.3 percent, compared to 98.3 percent in the first three months of 2022; combined cycle units had a capacity factor of 68.5 percent in the first three months of 2023, compared to a capacity factor of 61.9 percent in the first three months of 2022; coal units had a capacity factor of 31.7 percent in the first three months of 2023, compared to 48.1 percent in the first three months of 2022.

Table 5-30 Capacity factor (By unit type (GWh)): January through March, 2022 and 2023[175 176 177]

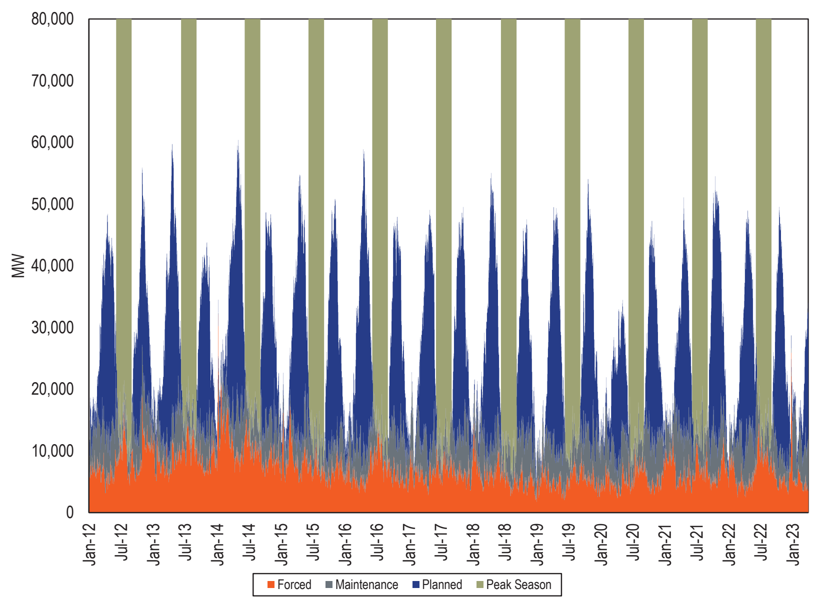
	2022 (Jan-Mar)		2023 (Jan-Mar)		
Unit Type	Generation (GWh)	Capacity Factor	Generation (GWh)	Capacity Factor	Change in 2023 from 2022
Battery	5.8	0.9%	6.0	1.0%	0.2%
Combined Cycle	71,707.0	61.9%	82,623.9	68.5%	6.7%
Single Fuel	63,221.5	70.0%	73,219.5	76.9%	6.9%
Dual Fuel	8,485.6	33.1%	9,404.4	37.0%	4.0%
Combustion Turbine	3,116.7	4.9%	2,137.0	3.5%	(1.5%)
Single Fuel	2,589.0	5.8%	1,690.3	3.9%	(1.9%)
Dual Fuel	527.7	2.8%	446.7	2.4%	(0.4%)
Diesel	68.8	7.8%	100.6	11.4%	3.6%
Single Fuel	65.2	8.2%	96.6	12.2%	4.0%
Dual Fuel	3.7	4.1%	4.0	4.5%	0.4%
Diesel (Landfill gas)	316.6	48.1%	267.5	46.4%	(1.7%)
Fuel Cell	53.1	88.2%	48.3	80.3%	(7.9%)
Nuclear	69,238.6	98.3%	67,873.9	96.3%	(1.9%)
Pumped Storage Hydro	1,518.1	12.6%	1,484.0	12.4%	(0.3%)
Run of River Hydro	2,487.2	38.9%	2,602.3	44.7%	5.9%
Solar	1,727.4	16.3%	1,899.7	15.7%	(0.6%)
Steam	52,333.9	41.7%	31,659.2	27.4%	(14.2%)
Biomass	1,321.3	65.5%	1,294.1	64.7%	(0.8%)
Coal	49,187.8	48.1%	29,247.7	31.7%	(16.3%)
Single Fuel	47,499.5	48.6%	29,247.7	31.7%	(16.9%)
Dual Fuel	1,688.2	36.1%	0.0	0.0%	(36.1%)
Natural Gas	1,531.0	40.4%	886.7	44.3%	3.9%
Single Fuel	107.8	51.5%	96.0	56.5%	5.0%
Dual Fuel	1,423.2	17.1%	790.6	17.6%	0.5%
Oil	293.8	3.5%	230.7	4.1%	0.6%
Wind	9,715.6	39.7%	9,928.5	39.8%	0.2%
Total	212,288.8	49.3%	200,630.9	47.2%	(2.1%)

Generator Performance Factors

Generator outages fall into three categories: planned, maintenance, and forced. The scheduling of planned and maintenance outages must be approved by PJM. The approval may be withdrawn in order to maintain system reliability.[178] The PJM Market Rules do not specify any consequences if the planned outage continues after PJM withdraws approval. If PJM withdraws approval for a maintenance outage during the outage and the unit cannot operate, the outage is defined to be a forced outage.[179] Outages that are approved by PJM may be extended. An extension to a planned outage that enters the peak period is treated as a forced outage. A maintenance outage that is extended to more than nine days during the peak period is treated as a forced outage.

The MW on outage vary during the year. For example, the MW on planned outage are generally highest in the spring and fall, as shown in Figure 5-7, as a result of restrictions on planned outages during the winter and summer. The Peak Period Maintenance Season, shown in Figure 5-7, runs from the weeks containing the twenty-fourth through thirty-sixth Wednesdays of the year. Planned outages cannot start in nor extend into this period. In 2022, the period ran from Monday, June 13 until Friday, September 9. The effect of the seasonal variation in outages can be seen in the monthly generator performance metrics in Figure 5-10.

Figure 5-7 Outages (MW): 2012 through March 2023



175 The capacity factors in this table are based on nameplate capacity values, and are calculated based on when the units come on line.
176 The subcategories of steam units are consolidated consistent with confidentiality rules. Coal is comprised of coal and waste coal. Natural gas is comprised of natural gas and propane. Oil is comprised of both heavy and light oil. Biomass is comprised of biomass, landfill gas, and municipal solid waste.
177 Hours in which batteries have net negative generation do not count toward their runtime.
178 "PJM Manual 10: Pre-Scheduling Operations," § 2.3.2 Maintenance Outage Rules, Rev. 40 (Dec. 15, 2021).
179 OATT, Attachment K (Appendix) § 1.9.3 (b).

In the first three months of 2023, forced outages were 17.8 percent lower, planned outages were 5.2 percent lower, and maintenance outages were 25.1 percent lower than in the first three months of 2022.

Performance factors include the equivalent availability factor (EAF), the equivalent maintenance outage factor (EMOF), the equivalent planned outage factor (EPOF) and the equivalent forced outage factor (EFOF). These four factors add to 100 percent for any generating unit. The EAF is the proportion of hours in a year when a unit is available to generate at full capacity while the three outage factors include all the hours when a unit is unavailable. The EMOF is the proportion of hours in a year when a unit is unavailable because of maintenance outages and maintenance deratings. The EPOF is the proportion of hours in a year when a unit is unavailable because of planned outages and planned deratings. The EFOF is the proportion of hours in a year when a unit is unavailable because of forced outages and forced deratings.

The PJM aggregate EAF, EFOF, EPOF, and EMOF are shown in Figure 5-8. Metrics by unit type are shown in Table 5-31.

Figure 5-8 Equivalent outage and availability factors: January through March, 2007 to 2023

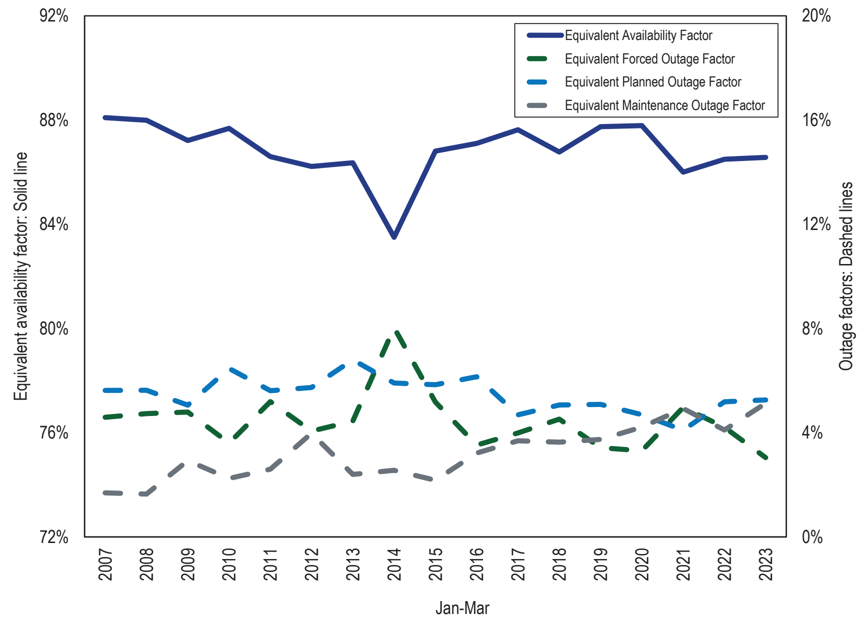


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Table 5-31 EFOF, EPOF, EMOF and EAF by unit type: January through March, 2007 to 2023

	Coal				Combined Cycle				Combustion Turbine				Diesel			
Jan-Mar	EFOF	EPOF	EMOF	EAF	EFOF	EPOF	EMOF	EAF	EFOF	EPOF	EMOF	EAF	EFOF	EPOF	EMOF	EAF
2007	6.8%	7.1%	2.0%	84.1%	1.5%	6.4%	1.1%	91.0%	5.8%	2.3%	2.5%	89.4%	8.0%	0.3%	1.6%	90.2%
2008	8.1%	5.5%	2.1%	84.3%	1.8%	2.5%	1.4%	94.3%	3.5%	4.1%	1.3%	91.1%	10.1%	0.2%	0.9%	88.8%
2009	6.8%	5.9%	3.4%	83.9%	3.6%	5.3%	3.3%	87.9%	1.9%	2.8%	1.9%	93.4%	6.6%	0.2%	1.7%	91.5%
2010	6.3%	7.7%	3.7%	82.3%	1.3%	5.7%	2.3%	90.7%	2.5%	1.7%	1.3%	94.5%	4.1%	0.7%	0.7%	94.5%
2011	9.6%	7.0%	4.2%	79.3%	3.1%	7.6%	1.9%	87.4%	1.7%	2.6%	1.6%	94.1%	2.5%	0.0%	3.6%	93.9%
2012	7.4%	7.3%	7.6%	77.7%	1.8%	5.6%	1.9%	90.8%	1.6%	2.2%	1.3%	94.8%	1.9%	0.0%	0.8%	97.3%
2013	6.5%	9.4%	3.9%	80.2%	2.2%	9.9%	3.2%	84.7%	5.6%	2.9%	0.8%	90.8%	3.6%	0.1%	1.2%	95.1%
2014	10.3%	5.3%	3.8%	80.7%	4.1%	10.2%	1.6%	84.1%	15.1%	3.4%	1.2%	80.3%	15.0%	0.0%	2.3%	82.7%
2015	8.1%	5.1%	3.4%	83.4%	2.6%	6.8%	1.6%	89.0%	3.7%	4.1%	1.1%	91.1%	10.0%	0.3%	1.9%	87.7%
2016	6.8%	7.0%	6.3%	79.9%	2.1%	4.2%	1.5%	92.2%	2.3%	2.6%	1.6%	93.5%	5.9%	0.0%	2.9%	91.2%
2017	9.4%	5.8%	7.5%	77.3%	2.2%	4.3%	1.5%	91.9%	1.0%	2.5%	1.8%	94.7%	4.5%	0.2%	1.4%	93.8%
2018	10.2%	6.2%	7.6%	76.0%	1.7%	4.0%	1.1%	93.1%	1.9%	3.1%	1.6%	93.5%	6.2%	0.7%	2.8%	90.3%
2019	8.1%	3.7%	7.1%	81.1%	1.3%	6.1%	1.5%	91.0%	1.6%	4.6%	2.3%	91.6%	6.1%	1.1%	2.9%	89.9%
2020	4.0%	3.9%	10.3%	81.8%	4.8%	5.8%	1.4%	88.0%	1.6%	4.0%	1.4%	93.0%	6.6%	0.3%	2.7%	90.4%
2021	8.5%	4.9%	10.3%	76.4%	2.4%	3.6%	3.4%	90.6%	1.6%	3.9%	3.4%	91.1%	6.0%	0.0%	3.2%	90.8%
2022	9.4%	6.0%	8.5%	76.1%	2.0%	7.2%	2.6%	88.3%	2.0%	3.8%	1.8%	92.4%	9.6%	0.5%	5.1%	84.8%
2023	6.4%	4.7%	10.1%	78.8%	3.2%	5.0%	2.5%	89.2%	1.6%	4.0%	2.4%	92.0%	12.6%	0.0%	4.0%	83.4%

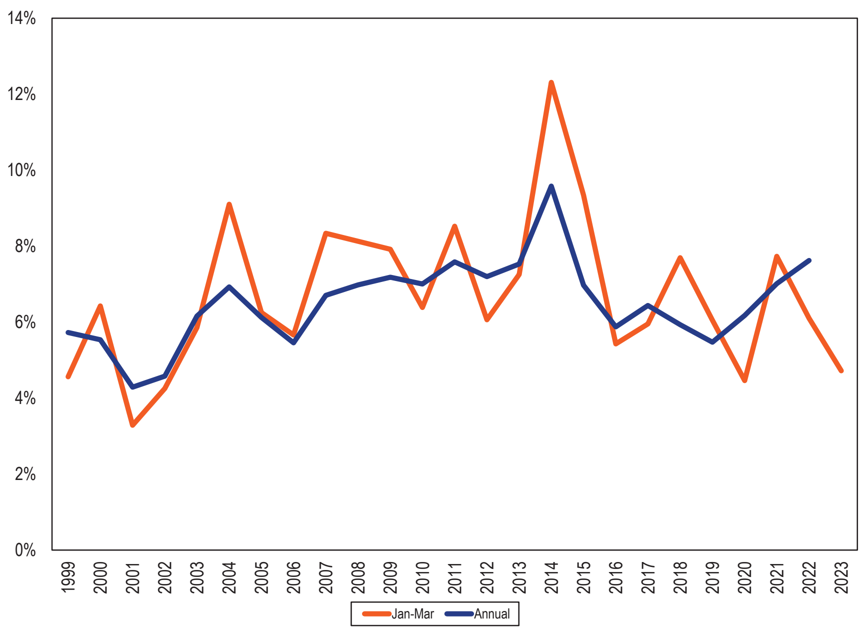
	Hydroelectric				Nuclear				Other				Total			
Jan-Mar	EFOF	EPOF	EMOF	EAF	EFOF	EPOF	EMOF	EAF	EFOF	EPOF	EMOF	EAF	EFOF	EPOF	EMOF	EAF
2007	1.1%	7.8%	2.1%	89.0%	0.4%	5.0%	0.3%	94.2%	7.8%	4.4%	2.6%	85.2%	4.6%	5.6%	1.7%	88.1%
2008	1.2%	9.3%	0.6%	88.9%	1.5%	7.3%	0.6%	90.5%	3.9%	7.1%	3.0%	86.1%	4.7%	5.6%	1.6%	88.0%
2009	1.6%	10.5%	1.3%	86.6%	4.0%	3.4%	1.1%	91.5%	5.1%	6.0%	6.7%	82.2%	4.8%	5.1%	2.9%	87.2%
2010	0.7%	9.5%	1.3%	88.5%	0.7%	7.1%	0.4%	91.8%	3.8%	7.1%	1.7%	87.4%	3.6%	6.5%	2.2%	87.7%
2011	1.7%	10.1%	0.8%	87.4%	1.6%	3.3%	0.7%	94.3%	4.0%	5.2%	3.0%	87.8%	5.2%	5.6%	2.6%	86.6%
2012	1.7%	4.1%	1.5%	92.8%	0.8%	6.0%	0.6%	92.7%	4.5%	5.6%	3.5%	86.4%	4.1%	5.7%	4.0%	86.2%
2013	0.4%	3.7%	2.4%	93.4%	0.2%	3.4%	0.2%	96.2%	8.1%	6.6%	2.5%	82.8%	4.4%	6.8%	2.4%	86.4%
2014	1.1%	9.5%	5.9%	83.5%	0.9%	4.6%	0.3%	94.2%	10.6%	7.8%	4.8%	76.8%	8.0%	5.9%	2.6%	83.5%
2015	2.1%	10.0%	1.4%	86.5%	1.6%	4.6%	0.6%	93.2%	9.2%	11.0%	3.9%	75.9%	5.2%	5.8%	2.2%	86.8%
2016	2.1%	5.3%	3.9%	88.7%	0.5%	5.0%	0.5%	94.0%	4.0%	15.3%	3.8%	76.9%	3.5%	6.2%	3.2%	87.1%
2017	2.4%	5.6%	3.6%	88.5%	0.4%	4.8%	0.5%	94.3%	2.6%	4.7%	4.8%	87.9%	4.0%	4.7%	3.7%	87.6%
2018	3.2%	4.3%	2.1%	90.4%	0.3%	4.9%	0.3%	94.5%	4.6%	7.8%	6.5%	81.2%	4.5%	5.1%	3.6%	86.8%
2019	1.0%	5.6%	3.4%	90.1%	0.2%	5.4%	0.7%	93.7%	3.3%	8.4%	6.8%	81.5%	3.4%	5.1%	3.7%	87.7%
2020	3.4%	3.7%	1.8%	91.1%	2.2%	4.2%	0.8%	92.7%	3.1%	8.3%	4.1%	84.5%	3.3%	4.7%	4.2%	87.8%
2021	16.2%	0.6%	2.3%	80.9%	0.1%	3.8%	1.6%	94.5%	12.9%	5.7%	2.4%	79.1%	5.0%	4.1%	4.9%	86.0%
2022	5.3%	2.7%	2.4%	89.5%	0.4%	3.7%	1.5%	94.3%	4.0%	5.6%	4.0%	86.4%	4.2%	5.2%	4.1%	86.5%
2023	1.5%	17.1%	6.4%	75.0%	0.1%	3.5%	1.9%	94.4%	2.8%	8.6%	8.8%	79.8%	3.0%	5.3%	5.1%	86.6%

Generator Outage Rates

The most fundamental forced outage rate metric is the equivalent demand forced outage rate (EFORd). EFORd is a measure of the probability that a generating unit will fail, either partially or totally, to perform when it is needed to operate. EFORd measures the forced outage rate during periods of demand, and does not include planned or maintenance outages. A period of demand is a period during which a generator is running or needed to run. EFORd calculations use historical performance data, including equivalent forced outage hours, service hours, average forced outage duration, average run time, average time between unit starts, available hours and period hours.[180] The EFORd metric includes all forced outages, regardless of the reason for those outages.

The average PJM EFORd in the first three months of 2023 was 4.7 percent, a decrease from 6.1 percent in the first three months of 2022. Figure 5-9 shows the average EFORd since 1999 for all units in PJM.[181]

Figure 5-9 Equivalent demand forced outage rates (EFORd): January through March, 1999 to 2023



180 Equivalent forced outage hours are the sum of all forced outage hours in which a generating unit is fully inoperable and all partial forced outage hours in which a generating unit is partially inoperable, prorated to full hours.
181 The universe of units in PJM changed as the PJM footprint expanded and as units retired from and entered PJM markets. See the *2022 State of the Market Report for PJM*, Appendix A: "PJM Overview" for details.

Table 5-32 shows the class average EFORd by unit type.

Table 5-32 EFORd by unit type: January through March, 2007 to 2023

	Jan-Mar																
	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Coal	7.4%	8.7%	7.8%	7.8%	11.2%	9.3%	7.8%	11.3%	9.3%	8.5%	11.5%	12.7%	11.0%	5.6%	11.5%	10.6%	10.2%
Combined Cycle	9.3%	5.2%	5.3%	3.6%	4.1%	2.3%	2.9%	7.1%	4.7%	2.8%	2.6%	3.2%	2.9%	5.2%	2.9%	3.0%	3.9%
Combustion Turbine	21.5%	17.6%	15.2%	14.0%	12.8%	8.9%	18.3%	31.5%	20.1%	8.2%	6.0%	10.5%	8.9%	4.9%	5.0%	6.4%	4.7%
Diesel	9.0%	10.0%	8.1%	6.2%	5.1%	2.8%	3.8%	15.7%	11.1%	6.9%	5.9%	6.6%	6.6%	7.5%	6.4%	10.3%	14.0%
Hydroelectric	1.6%	3.0%	2.0%	0.9%	2.2%	2.8%	0.6%	1.5%	2.4%	3.2%	3.1%	3.6%	1.2%	4.2%	16.9%	6.4%	1.6%
Nuclear	0.4%	1.6%	4.0%	0.8%	1.7%	0.8%	0.2%	1.1%	1.6%	0.5%	0.5%	0.4%	0.3%	2.3%	0.2%	0.5%	0.1%
Other	10.8%	10.2%	10.6%	5.6%	13.2%	4.6%	10.5%	19.1%	17.6%	6.4%	6.4%	12.6%	6.2%	2.7%	28.0%	10.6%	2.8%
Total	8.3%	8.1%	7.9%	6.4%	8.5%	6.1%	7.3%	12.3%	9.3%	5.4%	6.0%	7.7%	6.0%	4.5%	7.7%	6.1%	4.7%

EFORd vs EAF

EFORd is not an adequate measure of units' availability because EFORd measures only forced outages and does not account for planned or maintenance outages. Forced outage rates can be managed under the existing outage rules. A unit with significant planned and/or maintenance outages is considered to have identical reliability properties in capacity planning, transmission planning and in the sale of capacity in the capacity market.[182] The EAF (Equivalent Availability Factor), which reflects all forced, planned, and maintenance outages, is a more accurate measure of the capacity actually available to meet load.

Table 5-33 shows the differences between EFORd and EAF by unit type.

Table 5-33 EFORd and EAF by unit type: January through March, 2012 to 2023

	Unit Types															
	Coal		Combined Cycle		Combustion Turbine		Diesel		Hydroelectric		Nuclear		Other		All	
Year	EFORd	1-EAF	EFORd	1-EAF	EFORd	1-EAF	EFORd	1-EAF	EFORd	1-EAF	EFORd	1-EAF	EFORd	1-EAF	EFORd	1-EAF
2012	9.3%	22.3%	2.3%	9.2%	8.9%	5.2%	2.8%	2.7%	2.8%	7.2%	0.8%	7.3%	4.6%	13.6%	6.1%	13.8%
2013	7.8%	19.8%	2.9%	15.3%	18.3%	9.2%	3.8%	4.9%	0.6%	6.6%	0.2%	3.8%	10.5%	17.2%	7.3%	13.6%
2014	11.3%	19.3%	7.1%	15.9%	31.5%	19.7%	15.7%	17.3%	1.5%	16.5%	1.1%	5.8%	19.1%	23.2%	12.3%	16.5%
2015	9.3%	16.6%	4.7%	11.0%	20.1%	8.9%	11.1%	12.3%	2.4%	13.5%	1.6%	6.8%	17.6%	24.1%	9.3%	13.2%
2016	8.5%	20.1%	2.8%	7.8%	8.2%	6.5%	6.9%	8.8%	3.2%	11.3%	0.5%	6.0%	6.4%	23.1%	5.4%	12.9%
2017	11.5%	22.7%	2.6%	8.1%	6.0%	5.3%	5.9%	6.2%	3.1%	11.5%	0.5%	5.7%	6.4%	12.1%	6.0%	12.4%
2018	12.7%	24.0%	3.2%	6.9%	10.5%	6.5%	6.6%	9.7%	3.6%	9.6%	0.4%	5.5%	12.6%	18.8%	7.7%	13.2%
2019	11.0%	18.9%	2.9%	9.0%	8.9%	8.4%	6.6%	10.1%	1.2%	9.9%	0.3%	6.3%	6.2%	18.5%	6.0%	12.3%
2020	5.6%	18.2%	5.2%	12.0%	4.9%	7.0%	7.5%	9.6%	4.2%	8.9%	2.3%	7.3%	2.7%	15.5%	4.5%	12.2%
2021	11.5%	23.6%	2.9%	9.4%	5.0%	8.9%	6.4%	9.2%	16.9%	19.1%	0.2%	5.5%	28.0%	20.9%	7.7%	14.0%
2022	10.6%	23.9%	3.0%	11.8%	6.4%	7.6%	10.3%	15.2%	6.4%	10.5%	0.5%	5.7%	10.6%	13.6%	6.1%	13.5%
2023	10.2%	21.2%	3.9%	10.8%	4.7%	8.0%	14.0%	16.6%	1.6%	25.0%	0.1%	5.6%	2.8%	20.2%	4.7%	13.4%
Average	9.9%	20.9%	3.6%	10.6%	11.1%	8.4%	8.1%	10.2%	4.0%	12.5%	0.7%	5.9%	10.6%	18.4%	6.9%	13.4%

182 OATT, Attachment DD (Reliability Pricing Model) § 10A (d).

Outage Analysis

The MMU analyzed the causes of outages for the PJM system. The metric used was lost generation, which is the product of the duration of the outage and the size of the outage reduction. Lost generation can be converted into lost system equivalent availability.[183] On a system wide basis, the resultant lost equivalent availability from forced outages is equal to the equivalent forced outage factor (EFOF), the resultant lost equivalent availability from maintenance outages is equal to the equivalent maintenance outage factor (EMOF), and the resultant lost equivalent availability from planned outages is equal to the equivalent planned outage factor (EPOF).

The PJM EFOF was 3.0 percent in the first three months of 2023. Table 5-34 shows the causes of EFOF by unit type. Forced outages for boiler tube leaks, 16.3 percent of the system EFOF, were the largest single contributor to EFOF.

Table 5-34 Contribution to PJM EFOF by unit type by cause: January through March, 2023

	Coal	Combined Cycle	Combustion Turbine	Diesel	Hydroelectric	Nuclear	Other	System
Unit Testing	9.8%	13.4%	12.4%	43.2%	12.0%	0.0%	56.1%	16.3%
Boiler Tube Leaks	16.9%	10.4%	0.0%	0.0%	0.0%	0.0%	8.2%	12.1%
Electrical	1.1%	47.6%	1.7%	5.1%	3.5%	0.0%	0.3%	11.0%
Boiler Air and Gas Systems	17.9%	0.0%	0.0%	0.0%	0.0%	0.0%	7.6%	10.4%
Low Pressure Turbine	12.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	6.4%
Auxiliary Systems	0.6%	3.1%	44.1%	0.0%	0.0%	0.0%	0.0%	5.8%
NOx Reduction Systems	8.1%	0.3%	0.0%	0.0%	0.0%	0.0%	0.0%	4.4%
Feedwater System	4.2%	1.6%	0.0%	0.0%	0.0%	90.0%	3.4%	3.4%
Miscellaneous (Balance of Plant)	5.5%	0.1%	0.1%	0.0%	0.2%	0.0%	0.2%	3.0%
Controls	0.3%	8.6%	1.8%	2.8%	0.1%	0.4%	0.2%	2.2%
Boiler Internals and Structures	4.0%	0.3%	0.0%	0.0%	0.0%	0.0%	0.1%	2.2%
Waste Water (zero discharge)	4.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	2.2%
Miscellaneous (Pollution Control Equipment)	4.1%	0.0%	0.1%	0.0%	0.0%	0.0%	0.0%	2.2%
Generator	0.0%	0.0%	18.4%	0.0%	2.4%	0.0%	0.6%	2.1%
Turbine	0.0%	0.4%	4.2%	0.0%	54.7%	0.0%	0.0%	1.6%
Boiler Fuel Supply to Bunker	0.1%	0.0%	0.0%	0.0%	0.0%	0.0%	12.5%	1.4%
Boiler Fuel Supply from Bunkers to Boiler	2.0%	0.1%	0.0%	0.0%	0.0%	0.0%	1.5%	1.2%
Wet Scrubbers	2.3%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	1.2%
Economic	0.1%	1.0%	4.3%	3.1%	15.5%	0.0%	0.0%	1.0%
All Other Causes	7.0%	13.0%	12.9%	45.7%	11.7%	9.6%	9.3%	9.7%
Total	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%

183 For any unit, lost generation can be converted to lost equivalent availability by dividing lost generation by the product of the generating units' capacity and period hours. This can also be done on a system basis.

The PJM EMOF was 5.1 percent in the first three months of 2023. Table 5-35 shows the causes of EMOF by unit type. Maintenance outages for boiler tube leaks, 11.8 percent of the system EMOF, were the largest single contributor to system EMOF.

Table 5-35 Contribution to EMOF by unit type by cause: January through March, 2023

	Coal	Combined Cycle	Combustion Turbine	Diesel	Hydroelectric	Nuclear	Other	System
Boiler Tube Leaks	18.1%	9.6%	0.0%	0.0%	0.0%	0.0%	5.0%	11.8%
Electrical	7.0%	20.1%	4.6%	1.7%	3.0%	0.0%	7.4%	7.4%
Boiler Air and Gas Systems	11.0%	4.9%	0.0%	0.0%	0.0%	0.0%	0.4%	6.7%
NOx Reduction Systems	10.4%	0.9%	0.1%	0.0%	0.0%	0.0%	0.0%	5.9%
Wet Scrubbers	10.3%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	5.8%
Miscellaneous (Steam Turbine)	0.2%	1.2%	0.0%	0.0%	0.0%	0.0%	39.1%	5.1%
Water Supply/Discharge	0.0%	0.0%	0.0%	0.0%	92.0%	0.0%	0.0%	4.9%
Miscellaneous (Reactor)	0.0%	0.0%	0.0%	0.0%	0.0%	62.7%	0.0%	4.9%
Miscellaneous (Boiler)	2.2%	0.2%	0.0%	0.0%	0.0%	0.0%	26.9%	4.6%
Boiler Piping System	4.4%	19.2%	0.0%	0.0%	0.0%	0.0%	0.6%	4.5%
Boiler Overhaul and Inspections	6.1%	2.1%	0.0%	0.0%	0.0%	0.0%	3.9%	4.1%
Boiler Fuel Supply to Bunker	6.9%	0.0%	0.0%	0.0%	0.0%	0.0%	2.1%	4.1%
Miscellaneous (Gas Turbine)	0.0%	10.9%	33.9%	0.0%	0.0%	0.0%	0.0%	3.7%
Circulating Water Systems	6.2%	0.0%	0.0%	0.0%	0.0%	0.1%	0.0%	3.5%
Feedwater System	3.0%	4.9%	0.0%	0.0%	0.0%	1.0%	1.9%	2.5%
Reactor Coolant System	0.0%	0.0%	0.0%	0.0%	0.0%	26.5%	0.0%	2.1%
Boiler Control Systems	2.8%	0.1%	0.0%	0.0%	0.0%	0.0%	0.0%	1.6%
Miscellaneous (External)	0.3%	0.0%	17.2%	3.0%	0.6%	0.0%	0.0%	1.5%
Fuel, Ignition and Combustion Systems	0.0%	5.2%	12.5%	0.0%	0.0%	0.0%	0.0%	1.5%
All Other Causes	11.1%	20.7%	31.7%	95.3%	4.4%	9.7%	12.7%	13.6%
Total	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%

PJM EPOF was 5.3 percent in the first three months of 2023. Table 5-36 shows the causes of EPOF by unit type. Planned outages for miscellaneous gas turbine issues, 19.7 percent of the system EPOF, were the largest single contributor to system EPOF.

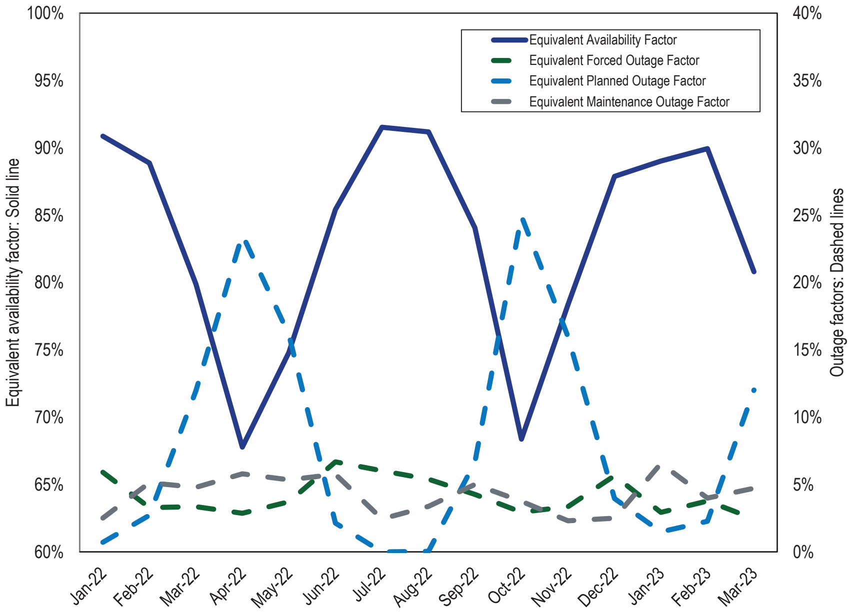
Table 5-36 Contribution to EPOF by unit type and cause: January through March, 2023

	Coal	Combined Cycle	Combustion Turbine	Diesel	Hydroelectric	Nuclear	Other	System
Miscellaneous (Gas Turbine)	0.0%	54.3%	66.5%	0.0%	0.0%	0.0%	0.0%	19.7%
Core/Fuel	0.0%	0.0%	0.0%	0.0%	0.0%	100.0%	0.0%	14.9%
Miscellaneous (Balance of Plant)	27.2%	25.0%	5.2%	0.0%	0.0%	0.0%	0.0%	12.0%
Boiler Overhaul and Inspections	22.9%	0.1%	0.0%	0.0%	0.0%	0.0%	46.6%	11.1%
Miscellaneous (Generator)	19.5%	0.0%	11.2%	0.0%	19.7%	0.0%	0.0%	9.3%
Miscellaneous	0.0%	0.0%	0.0%	0.0%	50.5%	0.0%	0.0%	8.2%
Turbine	0.0%	0.0%	0.0%	0.0%	26.0%	0.0%	0.0%	4.2%
Boiler Piping System	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	32.9%	4.0%
Miscellaneous (Steam Turbine)	0.2%	18.2%	0.0%	0.0%	0.0%	0.0%	0.7%	3.7%
Boiler Air and Gas Systems	11.9%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	2.8%
Miscellaneous Boiler Tube Problems	10.9%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	2.6%
Miscellaneous (Pollution Control Equipment)	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	17.9%	2.2%
Slag and Ash Removal	6.3%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	1.5%
Fuel, Ignition and Combustion Systems	0.0%	1.9%	6.3%	0.0%	0.0%	0.0%	0.0%	1.2%
Miscellaneous (Jet Engine)	0.0%	0.0%	6.6%	0.0%	0.0%	0.0%	0.0%	0.9%
Generator	0.0%	0.0%	0.0%	0.0%	3.6%	0.0%	1.5%	0.8%
Power Station Switchyard	0.0%	0.0%	2.3%	0.0%	0.1%	0.0%	0.0%	0.3%
High Pressure Turbine	0.9%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.2%
Electrical	0.0%	0.0%	0.8%	0.0%	0.0%	0.0%	0.1%	0.1%
All Other Causes	0.1%	0.5%	0.9%	100.0%	0.2%	0.0%	0.2%	0.3%
Total	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%

Performance by Month

Monthly values for EAF, EFOF, EMOF and EPOF are shown in Figure 5-10.

Figure 5-10 Monthly generator performance factors: 2022 through March 2023



Generator Testing Issues

PJM Manual 21: Rules and Procedures for Determination of Generating Capability describes how generators are to be tested. PJM's testing requirements are not well designed, permit excessive generator discretion, and do not require adequate winter testing.

Net Capability Verification Testing data, meant to demonstrate that a unit has the ICAP claimed, are submitted for the summer and winter testing periods.[184] These periods run from the start of June until September and the start of December until March. If a unit is on a planned or maintenance outage for the entire testing period, it is expected to perform an out of period test once the outage ends. Out of period tests can be performed from the start of September until December for summer tests and from the start of March until June for winter tests. Hydroelectric generators only perform summer tests.[185] Wind and solar resources do not perform verification tests to prove capability.[186]

While data must be submitted for the winter testing period, PJM permits the use of summer test data adjusted for ambient winter conditions in lieu of actual winter test data. The MMU recommends that PJM require actual seasonal tests as part of the Summer/Winter Capability Testing rules and that the ambient conditions under which the tests are performed be defined.

Results, including failed test results, must be submitted to PJM via eGADS. Failing to submit data before the deadline can result in a Data Submission Charge of $500 per day late.[187]

Failure to demonstrate the claimed net capability results in a forced outage or derating effective from the beginning of the testing period and lasting until either a reduced claimed ICAP is in effect, the beginning of the next testing period, or, except for failures due to environmental constraints or a lack of resources, a successful out of period test.

Failed test results must be accompanied by a derating or outage in eGADS and in eDART. Failure to report failed tests and to derate the unit can result in a Generation Resource Rating Test Failure Charge, equal to the Daily Deficiency Rate multiplied by: the daily ICAP shortfall multiplied by one minus the effective EFORd for unlimited resources; the UCAP for the daily ICAP shortfall, for limited duration resources and combination resources.[188] There were no such charges assessed for 2023.

The Daily Deficiency Rate in dollars per MW-day is equal to the weighted average capacity resource clearing price from the RPM auction that resulted

184 PJM. "PJM Manual 18: PJM Capacity Market," § 8.5 Summer/Winter Capability Testing, Rev. 51 (Oct. 20, 2021).

185 PJM. "PJM Manual 6: PJM Capacity Market," § 8.5 Summer/Winter Capability Testing, Rev. 51 (Oct. 20, 2021).

186 PJM. "PJM Manual 18: PJM Capacity Market," Appendix B: Calculating Capacity Values for Wind and Solar Capacity Resources, Rev. 51 (Oct. 20, 2021).

187 "Reliability Assurance Agreement Among Load Serving Entities in the PJM Region," Schedule 12, Section A.

188 PJM. "PJM Manual 18: PJM Capacity Market," § 9.1.5 Generation Resource Rating Test Failure Charge, Rev. 51 (Oct. 20, 2021).

in the resource's commitment plus the greater of 20 percent of that clearing price or 20 dollars per MW-day.[189]

While generation owners are required to report failed tests and to derate their unit in eGADS, owners can perform an unlimited number of tests before submitting a successful result. The MMU recommends that PJM limit the number of tests that can be made before submitting final results and that the data be collected by power meter instead of being submitted in eGADS. The MMU recommends that PJM select the time and day for testing a unit, not the unit owner, and that this testing not be communicated in advance. Instead, a unit would be tested by how well it follows its dispatch signal. Under the current testing rules, generation owners have the opportunity to perform tests during more favorable conditions to achieve better performance.

Generator output is also assessed during Performance Assessment Intervals (PAIs), which occur when PJM declares an emergency action as listed in Manual 18, Section 8.4A. If a unit fails to perform as expected, generators may incur a Non-Performance Charge, which is equal to the performance shortfall multiplied by the Non-Performance Charge Rate.[190] Only forced outages are defined as non-performance. In 2022, PAIs occurred on June 13, June 14, June 15, December 23, and December 24. For the December 23 and 24 PAIs, PJM estimates that total non-performance charges will be between $1 and $2 billion.[191]

For each day of a delivery year, generators are required to meet their daily unforced capacity commitments. Generation owners have the option to buy replacement capacity that satisfies the same locational requirements.[192] [193] Failure to meet this commitment can result in a Daily Capacity Resource Deficiency Charge.[194] [195] This charge is equal to the Daily Deficiency Rate multiplied by the difference between a resource's daily commitments and daily position. Thirty resources were assessed for deficiency charges in 2021, 64 resources were assessed for deficiency charges in 2022, and 36 resources have been assessed for deficiency charges in 2023.

Changing Outage Types

Capacity resource owners have an incentive to minimize their forced outages to maximize capacity revenue and minimize penalties. Generation owners have had the ability to change the designation of the outage type after the initial submission to the eGADS database since 2014 (Table 5-37).

Table 5-37 Changed outages by unit type: 2014 through March 2023[196]

		Forced to Maintenance		Forced to Planned		Maintenance or Planned to Forced	
Unit Type	Year	No. Outages	MWh	No. Outages	MWh	No. Outages	MWh
Coal	2014	5	270,049	0	NA	1	2,794
	2015	0	NA	0	NA	25	876,920
	2016	1	271,304	0	NA	74	1,983,852
	2017	2	151,085	0	NA	48	1,246,484
	2018	1	1,520	0	NA	30	837,286
	2019	2	71,234	0	NA	43	618,382
	2020	1	8,587	0	NA	12	179,687
	2021	0	NA	0	NA	0	NA
	2022	0	NA	0	NA	0	NA
	2023 (Jan-Mar)	0	NA	0	NA	0	NA
	Total	12	773,779	0	NA	233	5,745,406
Combined Cycle	2014	1	3,803	2	1,105	1	28,067
	2015	2	24,685	0	NA	3	3,330
	2016	0	NA	1	65,664	24	145,432
	2017	3	5,786	0	NA	19	400,606
	2018	1	416	0	NA	16	52,214
	2019	0	NA	0	NA	11	94,756
	2020	0	NA	0	NA	13	19,037
	2021	0	NA	7	303,061	0	NA
	2022	0	NA	1	3,817	2	208
	2023 (Jan-Mar)	0	NA	0	NA	0	NA
	Total	7	34,690	11	373,648	89	743,650
Combustion Turbine	2014	9	26,990	3	15,027	22	25,865
	2015	0	NA	0	NA	13	27,567
	2016	0	NA	0	NA	48	55,233
	2017	0	NA	0	NA	19	29,586
	2018	0	NA	2	41,737	25	24,433
	2019	0	NA	1	340	28	37,483
	2020	0	NA	0	NA	27	41,312
	2021	0	NA	0	NA	5	25,094
	2022	0	NA	0	NA	5	25,497
	2023 (Jan-Mar)	0	NA	0	NA	0	NA
	Total	9	26,990	6	57,104	192	292,069

189 OATT, Attachment DD (Reliability Pricing Model) § 7.
190 OATT, Attachment DD (Reliability Pricing Model) § 10A.
191 PJM, Operating Committee (OC). Winter Storm Elliott Event (January 11, 2023). <https://www.pjm.com/-/media/committees-groups/committees/oc/2023/20230112/item-02---overview-of-winter-storm-elliott-weather-event.ashx>
192 "PJM Manual 21: Rules and Procedures for Determination of Generating Capability," § 1.3.6 Impacts of Test Results, Rev. 16 (Aug. 1, 2021).
193 OATT, Attachment DD (Reliability Pricing Model) § 7 (a).
194 PJM. "PJM Manual 18: PJM Capacity Market," § 8.2 RPM Commitment Compliance, Rev. 51 (Oct. 20, 2021).
195 OATT, Attachment DD (Reliability Pricing Model) § 8.
196 Year describes the year in which the outage started and not the year in which the outage designation was changed. There were no changes to unit outage status in the first three months of 2023.

Table 5-37 Changed outages by unit type: 2014 through March 2023 (continued)

		Forced to Maintenance		Forced to Planned		Maintenance or Planned to Forced	
Unit Type	Year	No. Outages	MWh	No. Outages	MWh	No. Outages	MWh
Diesel	2014	0	NA	0	NA	77	4,550
	2015	15	47	0	NA	182	5,439
	2016	0	NA	0	NA	217	5,579
	2017	2	145	0	NA	175	5,883
	2018	2	15	0	NA	235	4,414
	2019	0	NA	0	NA	238	23,066
	2020	2	311	0	NA	163	6,113
	2021	3	137	0	NA	3	27,059
	2022	4	5,492	0	NA	10	305
	2023 (Jan-Mar)	0	NA	0	NA	0	NA
	Total	28	6,147	0	NA	1,300	82,408
Hydroelectric	2014	1	3	0	NA	124	1,383,319
	2015	1	162	0	NA	152	952,608
	2016	4	780	0	NA	315	1,433,851
	2017	2	52,080	0	NA	123	598,766
	2018	4	82,395	0	NA	72	405,549
	2019	0	NA	0	NA	34	148,629
	2020	0	NA	0	NA	59	285,839
	2021	0	NA	0	NA	33	263,525
	2022	0	NA	0	NA	1	4,887
	2023 (Jan-Mar)	0	NA	0	NA	0	NA
	Total	12	135,420	0	NA	913	5,476,973
Nuclear	2014	0	NA	1	177,618	0	NA
	2015	0	NA	1	573	0	NA
	2016	0	NA	0	NA	0	NA
	2017	0	NA	0	NA	0	NA
	2018	0	NA	0	NA	0	NA
	2019	0	NA	0	NA	0	NA
	2020	0	NA	0	NA	2	22,903
	2021	0	NA	0	NA	0	NA
	2022	0	NA	0	NA	0	NA
	2023 (Jan-Mar)	0	NA	0	NA	0	NA
	Total	0	NA	2	178,191	2	22,903
Other	2014	5	103,981	0	NA	1	866
	2015	0	NA	0	NA	2	176,599
	2016	1	11,680	0	NA	18	159,781
	2017	2	231	1	28,636	12	85,071
	2018	3	7,555	0	NA	1	268
	2019	1	128,664	1	8,658	9	61,297
	2020	0	NA	0	NA	4	82,250
	2021	0	NA	0	NA	0	NA
	2022	0	NA	0	NA	0	NA
	2023 (Jan-Mar)	0	NA	0	NA	0	NA
	Total	12	252,111	2	37,294	47	566,132
All Units	2014	21	404,826	6	193,750	226	1,445,461
	2015	18	24,894	1	573	377	2,042,463
	2016	6	283,764	1	65,664	696	3,783,728
	2017	11	209,328	1	28,636	396	2,366,397
	2018	11	91,901	2	41,737	379	1,324,165
	2019	3	199,897	2	8,998	363	983,612
	2020	3	8,898	0	NA	280	637,141
	2021	3	137	7	303,061	41	315,679
	2022	4	5,492	1	3,817	18	30,896
	2023 (Jan-Mar)	0	NA	0	NA	0	NA
	Total	80	1,229,136	21	646,237	2,776	12,929,541

Demand Response

Markets require both a supply side and a demand side to function effectively. The demand side of wholesale electricity markets is underdeveloped. Wholesale power markets will be more efficient when the demand side of the electricity market becomes fully functional without depending on special programs as a proxy for full participation.

Overview

- **Demand Response Activity.** Demand response activity includes economic demand response (economic resources), emergency and pre-emergency demand response (demand resources), synchronized reserves and regulation. Economic demand response participates in the energy market. Emergency and pre-emergency demand response participates in the capacity market and energy market.[1] Demand response resources participate in the synchronized reserve market. Demand response resources participate in the regulation market.

  Total demand response revenue decreased by $103.3 million, 66.1 percent, from $156.4 million in the first three months of 2022 to $53.1 million in the first three months of 2023. Emergency demand response revenue accounted for 97.1 percent of all demand response revenue, economic demand response for 0.6 percent, demand response in the synchronized reserve market for 0.5 percent and demand response in the regulation market for 1.8 percent.

  Total emergency demand response revenue decreased by $101.5 million, 66.3 percent, from $153.0 million in the first three months of 2022 to $51.5 million in the first three months of 2023.[2] This decrease consisted of capacity market revenue.

  Economic demand response revenue decreased by $0.1 million, 22.2 percent, from $0.4 million in the first three months of 2022 to $0.3 million in the first three months of 2023.[3] Demand response revenue in the synchronized reserve market decreased by $1.6 million, 85.7 percent, from $1.9 million in the first three months of 2022 to $0.3 million in the first three months of 2023. Demand response revenue in the regulation market decreased by $0.1 million, 13.3 percent, from $1.0 million in the first three months of 2022 to $0.9 million in the first three months of 2023.

- **Demand Response Energy Payments are Uplift.** Energy payments to emergency and economic demand response resources are uplift. LMP does not cover energy payments although emergency and economic demand response can and does set LMP. Energy payments to emergency demand resources are paid by PJM market participants in proportion to their net purchases in the real-time market. Energy payments to economic demand resources are paid by real-time exports from PJM and real-time loads in each zone for which the load-weighted, average real-time LMP for the hour during which the reduction occurred is greater than or equal to the net benefits test price for that month.[4]

- **Demand Response Market Concentration.** The ownership of economic load response resources was highly concentrated in the first three months of 2022 and the first three months of 2023. The HHI for economic resource reductions increased by 1528 points from 7861 in the first two months of 2022 to 9459 in the first two months of 2023. The ownership of emergency load response resources is highly concentrated. The HHI for emergency load response committed MW was 2070 for the 2021/2022 Delivery Year. In the 2021/2022 Delivery Year, the four largest CSPs owned 85.3 percent of all committed demand response UCAP MW. The HHI for emergency demand response committed MW is 2051 for the 2022/2023 Delivery Year. In the 2022/2023 Delivery Year, the four largest CSPs own 82.8 percent of all committed demand response UCAP MW.

- **Limited Locational Dispatch of Demand Resources.** With full implementation of the Capacity Performance rules in the capacity market in the 2020/2021 Delivery Year, PJM should be able to individually dispatch any capacity performance resource, including demand resources. But PJM cannot dispatch demand resources by node with the current rules because demand resources are not registered to a node. Aggregation rules allow a

1 Emergency demand response refers to both emergency and pre-emergency demand response. With the implementation of the Capacity Performance design, there is no functional difference between the emergency and pre-emergency demand response resource.

2 The total credits and MWh numbers for demand resources were downloaded as of April 6, 2023 and may change as a result of continued PJM billing updates.

3 Economic credits are synonymous with revenue received for reductions under the economic load response program.

4 "PJM Manual 28: Operating Agreement Accounting," § 11.2.2, Rev. 90 (Jan. 25, 2023).

demand resource that incorporates many small end use customers to span an entire zone, which is inconsistent with nodal dispatch.

Recommendations

- The MMU recommends that PJM report the response of demand capacity resources to dispatch by PJM as the actual change in load rather than simply the difference between the amount of capacity purchased by the customer and the actual metered load. The current approach significantly overstates the response to PJM dispatch. (Priority: High. New recommendation. Status: Not adopted.)
- The MMU recommends, as a preferred alternative to including demand resources as supply in the capacity market, that demand resources be on the demand side of the markets, that customers be able to avoid capacity and energy charges by not using capacity and energy at their discretion, that customer payments be determined only by metered load, and that PJM forecasts immediately incorporate the impacts of demand side behavior. (Priority: High. First reported 2014. Status: Not adopted.)
- The MMU recommends that the option to specify a minimum dispatch price (strike price) for demand resources be eliminated and that participating resources receive the hourly real-time LMP less any generation component of their retail rate. (Priority: Medium. First reported 2010. Status: Not adopted.)
- The MMU recommends that the maximum offer for demand resources be the same as the maximum offer for generation resources. (Priority: Medium. First reported 2013. Status: Not adopted.)
- The MMU recommends that the demand resources be treated as economic resources, responding to economic price signals like other capacity resources. The MMU recommends that demand resources not be treated as emergency resources, not trigger a PJM emergency and not trigger a Performance Assessment Interval. The MMU recommends that demand resources be available for every hour of the year. (Priority: High. First reported 2012. Status: Not adopted.)
- The MMU recommends that the Emergency Program Energy Only option be eliminated because the opportunity to receive the appropriate energy market incentive is already provided in the economic program. (Priority: Low. First reported 2010. Status: Not adopted.)
- The MMU recommends that, if demand resources remain in the capacity market, a daily energy market must offer requirement apply to demand resources, comparable to the rule applicable to generation capacity resources.[5] (Priority: High. First reported 2013. Status: Not adopted.)
- The MMU recommends that demand resources be required to provide their nodal location, comparable to generation resources. (Priority: High. First reported 2011. Status: Not adopted.)
- The MMU recommends that PJM require nodal dispatch of demand resources with no advance notice required or, if nodal location is not required, subzonal dispatch of demand resources with no advance notice required. The MMU recommends that, if PJM continues to use subzones for any purpose, PJM clearly define the role of subzones in the dispatch of demand response. (Priority: High. First reported 2015. Status: Not adopted.)
- The MMU recommends that PJM not remove any defined subzones and maintain a public record of all created and removed subzones. (Priority: Low. First reported 2016. Status: Not adopted.)
- The MMU recommends that PJM eliminate the measurement of compliance across zones within a compliance aggregation area (CAA). The multiple zone approach is less locational than the zonal and subzonal approach and creates larger mismatches between the locational need for the resources and the actual response. (Priority: High. First reported 2015. Status: Not adopted.)
- The MMU recommends that measurement and verification methods for demand resources be modified to reflect compliance more accurately. (Priority: Medium. First reported 2009. Status: Not adopted.)
- The MMU recommends that compliance rules be revised to include submittal of all necessary hourly load data, and that negative values

5 See "Complaint and Motion to Consolidate of the Independent Market Monitor for PJM," Docket No. EL14-20-000 (January 27, 2014) at 1.

be included when calculating event compliance across hours and registrations. (Priority: Medium. First reported 2012. Status: Not adopted.)

- The MMU recommends that PJM adopt the ISO-NE five-minute metering requirements in order to ensure that operators have the necessary information for reliability and that market payments to demand resources be calculated based on interval meter data at the site of the demand reductions.[6] (Priority: Medium. First reported 2013. Status: Not adopted.)
- The MMU recommends demand response event compliance be calculated on a five minute basis for all capacity performance resources and that the penalty structure reflect five minute compliance. (Priority: Medium. First reported 2013. Status: Partially adopted.)
- The MMU recommends that load management testing be initiated by PJM with limited warning to CSPs in order to more accurately represent the conditions of an emergency event. (Priority: Low. First reported 2012. Status: Not adopted.)
- The MMU recommends that shutdown cost be defined as the cost to curtail load for a given period that does not vary with the measured reduction or, for behind the meter generators, be the start cost defined in Manual 15 for generators. (Priority: Low. First reported 2012. Status: Not adopted.)
- The MMU recommends that the Net Benefits Test be eliminated and that demand response resources be paid LMP less any generation component of the applicable retail rate. (Priority: Low. First reported 2015. Status: Not adopted.)
- The MMU recommends that the tariff rules for demand response clarify that a resource and its CSP, if any, must notify PJM of material changes affecting the capability of the resource to perform as registered and must terminate or modify registrations that are no longer capable of responding to PJM dispatch directives at defined levels because load has been reduced or eliminated, as in the case of bankrupt and/or out of service facilities. (Priority: Medium. First reported 2015. Status: Not adopted.)

6 See ISO-NE Tariff, Section III, Market Rule 1, Appendix E1 and Appendix E2, "Demand Response," <http://www.iso-ne.com/regulatory/tariff/sect_3/mr1_append-e.pdf>. (Accessed October 17, 2017) ISO-NE requires that DR have an interval meter with five-minute data reported to the ISO and each behind the meter generator is required to have a separate interval meter. After June 1, 2017, demand response resources in ISO-NE must also be registered at a single node.

- The MMU recommends that there be only one demand response product in the capacity market, with an obligation to respond when called for any hour of the delivery year. (Priority: High. First reported 2011. Status: Partially adopted.[7])
- The MMU recommends that the lead times for demand resources be shortened to 30 minutes with a one hour minimum dispatch for all resources. (Priority: Medium. First reported 2013. Status: Partially adopted.)
- The MMU recommends setting the baseline for measuring capacity compliance under winter compliance at the customers' PLC, similar to GLD, to avoid double counting. (Priority: High. First reported 2010. Status: Partially adopted.)
- The MMU recommends the Relative Root Mean Squared Test be required for all demand resources with a CBL. (Priority: Low. First reported 2017. Status: Partially adopted.)
- The MMU recommends that the limits imposed on the pre-emergency and emergency demand response share of the synchronized reserve market be eliminated. (Priority: Medium. First reported 2018. Status: Not adopted.)
- The MMU recommends that 30 minute pre-emergency and emergency demand response be considered to be 30 minute reserves. (Priority: Medium. First reported 2018. Status: Not adopted.)
- The MMU recommends that energy efficiency resources not be included in the capacity market and that PJM should ensure that the impact of EE measures on the load forecast is incorporated immediately rather than with the existing lag. (Priority: Medium. First reported 2018. Status: Partially adopted.)
- The MMU recommends that, if energy efficiency resources remain in the capacity market, PJM codify eligibility requirements to claim the capacity rights to energy efficiency installations in the tariff and that PJM institute a registration system to track claims to capacity rights to energy efficiency installations and document installation periods of energy efficiency installations. (Priority: Medium. First reported 2022. Status: Not adopted.)

7 PJM's Capacity Performance design requires resources to respond when called for any hour of the delivery year, but demand resources still have a limited mandatory compliance window.

- The MMU recommends that demand reductions based entirely on behind the meter generation be capped at the lower of economic maximum or actual generation output. (Priority: High. First reported 2019. Status: Not adopted.)
- The MMU recommends that all demand resources register as Pre-Emergency Load Response and that the Emergency Load Response Program be eliminated. (Priority: High. First reported 2020. Status: Not adopted.)
- The MMU recommends that EDCs not be allowed to participate in markets as DER aggregators in addition to their EDC role. (Priority: High. First reported 2021. Status: Not adopted.)
- The MMU recommends that PJM include a 5.0 MW maximum size cap on DER aggregations. (Priority: Medium. First reported 2021. Status: Not adopted.)
- The MMU recommends that PJM use a nodal approach for DER participation in PJM markets. (Priority: Medium. First reported 2022. Status: Partially adopted.)

Conclusion

A fully functional demand side of the electricity market means that end use customers or their designated intermediaries will have the ability to see real-time energy price signals in real time, will have the ability to react to real-time prices in real time and will have the ability to receive the direct benefits or costs of changes in real-time energy use. In addition, customers or their designated intermediaries will have the ability to see current capacity prices, will have the ability to react to capacity prices and will have the ability to receive the direct benefits or costs of changes in the demand for capacity in the same year in which demand for capacity changes. A functional demand side of these markets means that customers will have the ability to make decisions about levels of power consumption based both on how customers value the power and on the actual cost of that power.

In the energy market, if there is to be a demand side program, demand resources should be paid the value of energy, which is LMP less any generation component of the applicable retail rate. There is no reason to have the net benefits test. The necessity for the net benefits test is an illustration of the illogical approach to demand side compensation embodied in paying full LMP to demand resources. The benefit of demand side resources is not that they suppress market prices, but that customers can choose not to consume at the current price of power, that individual customers benefit from their choices and that the choices of all customers are reflected in market prices. If customers face the market price, customers should have the ability to not purchase power and the market impact of that choice does not require a test for appropriateness.

If demand resources are to continue competing directly with generation capacity resources in the PJM Capacity Market, the product must be defined such that it can actually serve as a substitute for generation. This is a prerequisite to a functional market design. Demand resources do not have a must offer requirement into the day-ahead energy market, are able to offer above $1,000 per MWh without providing a fuel cost policy, or any rationale for the offer. PJM automatically, and inappropriately, triggers a PAI when demand resources are dispatched and demand resources do not have telemetry requirements similar to other Capacity Performance resources.

In order to be a substitute for generation, demand resources should be defined in PJM rules as an economic resource, as generation is defined. Demand resources should be required to offer in the day-ahead energy market and should be called when the resources are required and prior to the declaration of an emergency. Demand resources should be available for every hour of the year. The fact that demand resources are only obligated to respond for defined time periods meant that PJM could not fully use demand resources during Winter Storm Elliott (Elliott). The fact that PJM currently defines demand resources as emergency resources and the fact that calling on demand resources triggers a performance assessment interval (PAI) under the Capacity Performance design, both serve as a significant disincentive to calling on demand resources and mean that demand resources are underused. Demand resources should be treated as economic resources like any other capacity resource. Demand resources should be called whenever economic and paid the LMP rather than an inflated strike price up to $1,849 per MWh that is set by the seller.

In order to be a substitute for generation, demand resources should be subject to robust measurement and verification techniques to ensure that transitional DR programs incent the desired behavior. The methods used in PJM programs today are not adequate to determine and quantify deliberate actions taken to reduce consumption.

In order to be a substitute for generation, demand resources should provide a nodal location and should be dispatched nodally to enhance the effectiveness of demand resources and to permit the efficient functioning of the energy market. Both subzonal and multi-zone compliance should be eliminated because they are inconsistent with an efficient nodal market.

In order to be a substitute for generation, compliance by demand resources with PJM dispatch instructions should include both increases and decreases in load. The current method applied by PJM simply ignores increases in load and thus artificially overstates compliance.

In order to be a substitute for generation, Actual Performance of demand resources during a Performance Assessment Event should be determined consistent with that of generation and should not be netted across the Emergency Action Area (EAA). The Capacity Market Seller's Performance Shortfalls for Demand Resources in the EAA are netted to determine a net EAA Performance Shortfall for the Performance Assessment Interval. Any net positive EAA Performance Shortfall is allocated to the Capacity Market Seller's demand resources that under complied within the EAA on a prorata basis based on the under compliance MW, and such seller's demand resources will be assessed a Performance Shortfall for the Performance Assessment Interval. Any net negative EAA Performance Shortfall is allocated to the Market Seller's Demand Resources that over complied within the EAA on a prorata basis based on over compliance MW, and such Market Seller's Demand Resources will be assessed Bonus Performance. Netting of performance of Demand Resources across the EAA is inconsistent with the performance measurement of other Capacity Performance resources.

In order to be a substitute for generation, any demand resource and its Curtailment Service Provider (CSP), should be required to notify PJM of material changes affecting the capability of the resource to perform as registered and to terminate or modify registrations that are no longer capable of responding to PJM dispatch directives at the specified level, such as in the case of bankrupt and out of service facilities. Generation resources are required to inform PJM of any change in availability status, including outages and shutdown status.

As a preferred alternative to being a substitute for generation in the capacity and energy markets, demand response resources should be on the demand side of the capacity market rather than on the supply side. Rather than detailed demand response programs with their attendant complex and difficult to administer rules, customers would be able to avoid capacity and energy charges by not using capacity and energy at their discretion and the level of usage paid for would be defined by metered usage rather than a complex and inaccurate measurement protocol.

The MMU peak shaving proposal at the Summer-Only Demand Response Senior Task Force (SODRSTF) is an example of how to create a demand side product that is on the demand side of the market and not on the supply side.[8] The MMU proposal was based on the BGE load forecasting program and the Pennsylvania Act 129 Utility Program.[9] [10] Under the MMU proposal, participating load would inform PJM prior to an RPM auction of the MW participating, the months and hours of participation and the temperature humidity index (THI) threshold at which load would be reduced. PJM would reduce the load forecast used in the RPM auction based on the designated reductions. Load would agree to curtail demand to at or below a defined FSL, less than the customer PLC, when the THI exceeds a defined level or load exceeds a specified threshold. By relying on metered load and the PLC, load can reduce its demand for capacity and that reduction can be verified without complicated and inaccurate metrics to estimate load reductions. Under PJM's

8 See the MMU package within the *SODRSTF Matrix*, <http://www.pjm.com/-/media/committees-groups/task-forces/sodrstf/20180802/20180802-item-04-sodrstf-matrix.ashx>.

9 *Advance signals that can be used to foresee demand response days*, BGE, <https://www.pjm.com/-/media/committees-groups/task-forces/sodrstf/20180309/20180309-item-05-bge-load-curtailment-programs.ashx> (Accessed April 28, 2022).

10 *Pennsylvania ACT 129 Utility Program*, CPower, <https://www.pjm.com/-/media/committees-groups/task-forces/sodrstf/20180413/20180413-item-03-pa-act-129-program.ashx> (Accessed April 28, 2022).

weakened version of the program, performance is be measured under the current economic demand response CBL rules which means relying on load estimates rather than actual metered load.[11] PJM's proposal includes only a THI curtailment trigger and not an overall load curtailment trigger.

The long term appropriate end state for demand resources in the PJM markets should be comparable to the demand side of any market. Customers should use energy as they wish, accounting for market prices in any way they like, and that usage will determine the amount of capacity and energy for which each customer pays. There would be no counterfactual measurement and verification.

Under this approach, customers that wish to avoid capacity payments would reduce their load during expected high load hours, not limited to a small number of peak hours. Capacity costs would be assigned to LSEs and by LSEs to customers, based on actual load on the system during these hours. Customers wishing to avoid high energy prices would reduce their load during high price hours. Customers would pay for what they actually use, as measured by meters, rather than relying on flawed measurement and verification methods. No measurement and verification estimates are required. No promises of future reductions which can only be verified by inaccurate and biased measurement and verification methods are required. To the extent that customers enter into contracts with CSPs or LSEs to manage their payments, measurement and verification can be negotiated as part of a bilateral commercial contract between a customer and its CSP or LSE. But the system would be paid for actual, metered usage, regardless of which contractual party takes that obligation.

This approach provides more flexibility to customers to limit usage at their discretion. There is no requirement to be available year round or every hour of every day. There is no 30 minute notice requirement. There is no requirement to offer energy into the day-ahead market. All decisions about interrupting are up to the customers only and they may enter into bilateral commercial arrangements with CSPs at their sole discretion. Customers would pay for capacity and energy depending solely on metered load.

11 The PJM proposal from the SODRSTF weakened the proposal but was approved at the October 25, 2018 Members Committee meeting and PJM filed Tariff changes on December 7, 2018. See "Peak Shaving Adjustment Proposal," Docket No. ER19-511-000 (December 7, 2018).

A transition to this end state should be defined in order to ensure that appropriate levels of demand side response are incorporated in PJM's load forecasts and thus in the demand curve in the capacity market. That transition should be defined by the PRD rules, modified as proposed by the MMU.

This approach would work under the CP design in the capacity market. This approach is entirely consistent with the Supreme Court decision in *EPSA* as it does not depend on whether FERC has jurisdiction over the demand side.[12] This approach will allow FERC to more fully realize its overriding policy objective to create competitive and efficient wholesale energy markets. The decision of the Supreme Court addressed jurisdictional issues and did not address the merits of FERC's approach. The Supreme Court's decision has removed the uncertainty surrounding the jurisdictional issues and created the opportunity for FERC to revisit its approach to demand side.

Any discussion of demand resource performance during a PAI must recognize the significant problems with the definition of performance for demand resources. As defined by PJM rules, performance, contrary to intuition, does not mean actually reducing load in response to a PJM request for demand resources. Performance means only that, on a net portfolio basis, the amount of capacity paid for in the capacity market (PLC) minus actual metered load is equal to the amount of demand side capacity sold in the capacity market (ICAP). If a demand resource location was already at a reduced load level when PJM called a PAI, the demand resource would be deemed to have performed if the PLC less the metered load level was equal to the ICAP sold in the capacity market. The standard reporting of demand side response is therefore misleading because it includes loads that were already lower for any reason as a response.

PJM Demand Response Programs

All PJM demand response programs can be grouped into economic, emergency and pre-emergency programs, or Price Responsive Demand (PRD). Table 6-1 provides an overview of the key features of PJM demand response programs.

12 577 U.S. 260 (2016).

Demand response activity includes economic demand response (economic resources), emergency and pre-emergency demand response (demand resources), synchronized reserves and regulation. Economic demand response participates in the energy market. Emergency and pre-emergency demand response participate in the capacity market and energy market.[13] Demand response resources participate in the synchronized reserve market. Demand response resources participate in the regulation market.

FERC Order No. 719 required PJM and other RTOs to amend their market rules to accept bids from aggregators of retail customers of utilities unless the laws or regulations of the relevant electric retail regulatory authority ("RERRA") do not permit the customers aggregated in the bid to participate.[14] PJM implemented rules that require PJM to verify with EDCs that no law or regulation of a RERRA prohibits end use customers' participation.[15] EDCs and their end use customers are categorized as small and large based on whether the EDC distributed more or less than 4 million MWh in the previous fiscal year. End use customers within a large EDC must provide verification of any other contractual obligations or laws or regulations that prohibit participation, but end use customers within a small EDC do not need to provide additional verification.[16] RERRAs have permitted EDCs, in a number of cases, to participate in the PJM Economic Load Response Program.

Table 6-1 Overview of demand response programs

	Emergency and Pre-Emergency Load Response Program			Economic Load Response Program	Price Responsive Demand
	Load Management (LM)			Economic Demand Response	
Product Types	Capacity Performance, Summer-Period Capacity Performance OATT Attachmend DD § 5.5A	Capacity Performance,Summer-Period Capacity Performance OATT Attachmend DD § 5.5A		OATT Attachment K § 1.5A	
Market	Capacity Only OATT Attachemnt K § 8.1	Full Program Option (Capacity and Energy) OATT Attachemnt K § 8.1	Energy Only OATT Attachemnt K § 8.1	Energy Only	Capacity Only
Capacity Market	DR cleared in RPM	DR cleared in RPM	Not included in RPM	Not included in RPM	PRD cleared in RPM
Dispatch Requirement	Mandatory Curtailment	Mandatory Curtailment	Voluntary Curtailment	Dispatched Curtailment	Price Threshold
Capacity Payments	Capacity payments based on RPM clearing price	Capacity payments based on RPM clearing price	NA	NA	LSE PRD Credit RAA Schedule 6.1.G
Capacity Measurement and Verification	Firm Service Level Guaranteed Load Drop	Firm Service Level Guaranteed Load Drop	NA	NA	Firm Service Level
CBL	NA	Yes, as described OATT Attachment K § 3.3A	Yes, as described OATT Attachment K § 3.3A	Yes, as described OATT Attachment K § 3.3A	NA
Energy Payments	No energy payment	Energy payment based on submitted higher of "minimum dispatch price" and LMP. Energy payment during PJM declared Emergency Event mandatory curtailments.	Energy payment based on submitted higher of "minimum dispatch price" and LMP. Energy payment only for voluntary curtailments.	Energy payment based on full LMP. Energy payment for hours of dispatched curtailment. OATT Attachment K § 3.3A	NA
Penalties	RPM event OATT Attachment DD § 10A RAA Schedule 6.K Test compliance penalties OATT Attachment DD § 11A	RPM event OATT Attachment DD § 10A RAA Schedule 6.K Test compliance penalties OATT Attachment DD § 11A	NA	NA	RPM event RAA Schedule 6.1.G Test compliance penalties RAA Schedule 6.1.L
Associate Manuals	Manual 18	Manual 11 Manual 18	Manual 11 Manual 18	Manual 11	Manual 18

13 Emergency demand response refers to both emergency and pre-emergency demand response. With the implementation of the Capacity Performance design, there is no functional difference between the emergency and pre-emergency demand response resource.
14 *Wholesale Competition in Regions with Organized Electric Markets*, Order No. 719, FERC Stats. & Regs. ¶ 31,281 at P 154 (2008), *order on reh'g*, Order No. 719-A, FERC Stats. & Regs. ¶ 31,292, *order on reh'g*, Order No. 719-B, 129 FERC ¶ 61,252 (2009).
15 The evidence supplied by LDCs must take the form of an order, resolution or ordinance of the RERRA, an opinion of the RERRA's legal counsel attesting to existence of an order, resolution, or ordinance, or an opinion of the state attorney general on behalf of the RERRA attesting to existence of an order, resolution or ordinance.
16 PJM Operating Agreement Schedule 1 § 1.5A.3.1.

Non-PJM Demand Response Programs

Within the PJM footprint, states may have additional demand response programs as part of a Renewable Portfolio Standard (RPS) or a separate program. Indiana, Ohio, Pennsylvania (e.g. Pennsylvania ACT 129 Utility Program) and North Carolina include demand response in their RPS. If demand response is dispatched by a state run program, the demand response resources are ineligible to receive payments from PJM during the state dispatch.[17]

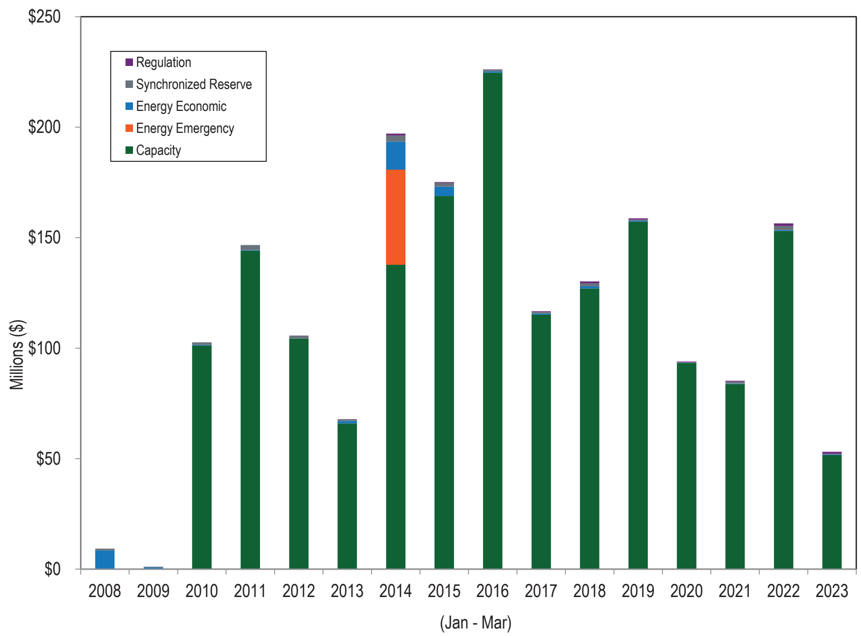
PJM Demand Response Programs

Figure 6-1 shows all revenue from PJM demand response programs by market for each year, 2008 through 2023. Since the implementation of the RPM Capacity Market on June 1, 2007, the capacity market (demand resources) has been the primary source of demand response revenue.[18] In the first three months of 2023, total demand response revenue decreased by $103.3 million, 66.1 percent, from $156.4 million in the first three months of 2022 to $53.1 million in the first three months of 2023. Total emergency demand response revenue decreased by $101.5 million, 66.3 percent, from $153.0 million in the first three months of 2022 to $51.5 million in the first three months of 2023. This decrease consisted of capacity market revenue.[19] In the first three months of 2023, emergency demand response revenue, which includes capacity and emergency energy revenue, accounted for 97.1 percent of all revenue received by demand response providers, the economic program for 0.6 percent, synchronized reserve for 0.5 percent and the regulation market for 1.8 percent.

Economic demand response revenue decreased by $0.1million, 22.2 percent, from $0.4 million in the first three months of 2022 to $0.3 million in the first three months of 2023.[20] Demand response revenue in the synchronized reserve market decreased by $1.6 million, 85.7 percent, from $1.9 million in the first three months of 2022 to $0.3 million in the first three months of 2023. Demand response revenue in the regulation market decreased by $0.1 million, 13.3 percent, from $1.0 million in the first three months of 2022 to $0.9 million in the first three months of 2023.

Lower demand resource revenues in the first three months of 2023, compared to 2022, are primarily due to capacity market revenues. The RTO clearing price for the RPM Base Residual Auction for the 2021/2022 Delivery Year was $140.00 per MW-day. The RTO clearing price for the RPM Base Residual Auction for the 2022/2023 Delivery Year was $50.00 per MW-day, 64.2 percent lower than the clearing price for the RTO Base Residual Auction for the 2021/2022 Delivery Year. The capacity revenue amounts for the first three months of 2022 are from the 2021/2022 Delivery Year and the capacity revenue amounts for the first three months of 2023 are from the 2022/2023 Delivery Year.

Figure 6-1 Demand response revenue by market: January through March, 2008 through 2023



17 "PJM Manual 11: Energy & Ancillary Services Market Operations," § 10.1, Rev. 123 (Feb. 9, 2023).
18 This includes both capacity market revenue and emergency energy revenue for capacity resources.
19 The total credits and MWh for demand resources were downloaded as of April 6, 2023 and may change as a result of continued PJM billing updates.
20 Economic credits are synonymous with revenue received for reductions under the economic load response program.

Emergency and Pre-Emergency Load Response Programs

Demand resources participate in the capacity market within the Emergency and Pre-Emergency Load Response Programs.

All demand resources must register as pre-emergency unless the participant relies on behind the meter generation and the resource has environmental restrictions that limit the resource's ability to operate only in emergency conditions.[21] Under current rules, PJM will declare an emergency if pre-emergency or emergency demand response is dispatched. In all demand response programs, CSPs are companies that sign up customers that have the ability to reduce load. CSPs satsify cleared RPM commitments registerting customers as Nominated MW. After a demand response event occurs, PJM compensates CSPs for their participants' load reductions and CSPs in turn compensate their participants. Only CSPs are eligible to participate in the PJM demand response programs, but a participant can register as a PJM special member and become a CSP without any additional cost.

The emergency and pre-emergency load response programs consist of the base and capacity performance demand response products. Full implementation of the Capacity Performance design in the 2020/2021 Delivery Year requires all emergency or pre-emergency demand resources to be registered as annual capacity resources. Summer period demand response resources are allowed to aggregate with winter period capacity resources to fulfill the annual requirement of the CP design.[22]

All capacity performance resource types must respond during a Performance Assessment Interval (PAI). Demand resources are the only capacity performance resource types that trigger a PAI when dispatched by PJM. PJM eliminated any substantive difference between pre-emergency and emergency by making the dispatch of either type trigger a PAI.

The rules applied to demand resources in the current market design do not treat demand resources in a manner comparable to generation capacity resources, even though demand resources are sold in the same capacity market, are treated as a substitute for other capacity resources and displace other capacity resources in RPM auctions. PJM will not measure compliance for DR, and the resources will not face penalties, in a PAI unless the product type and lead time type are dispatched by PJM. PJM will not measure compliance for DR, and the resources will not face penalties, in a PAI if the area dispatched is not a defined subzone or control zone. Demand resources are not required to meet the same requirements as other capacity resources for the PAI.

Demand resources are also not required to meet the same must offer requirements as other capacity resources. All other capacity resources must offer daily into the day-ahead energy market.

The MMU recommends that if demand resources remain on the supply side of the capacity market, a daily must offer requirement in the day-ahead energy market apply to demand resources, comparable to the rule applicable to generation capacity resources. This will help to ensure comparability and consistency for demand resources.

The MMU recommends eliminating the option to specify a minimum dispatch price under the Emergency and Pre-Emergency Program Full option and that participating resources receive the hourly real-time LMP less any generation component of their retail rate.[23]

Market Structure

The HHI for demand resources showed that ownership was highly concentrated for the 2021/2022 Delivery Year, with an HHI value of 2070. In the 2021/2022 Delivery Year, the four largest companies contributed 85.3 percent of all committed demand resources UCAP MW. The HHI for demand resources shows that ownership is highly concentrated for the 2022/2023 Delivery Year, with an HHI value of 2051. In the 2022/2023 Delivery Year, the four largest companies own 82.8 percent of all committed demand response UCAP MW.

21 OA Schedule 1 § 8.5.

22 Summer period demand response must be available for June through October and the following May between 10:00AM and 10:00PM EPT. *See* PJM OATT RAA Article 1.

23 See "Complaint and Motion to Consolidate of the Independent Market Monitor for PJM," Docket No. EL14-20-000 (January 28, 2014), "Comments of the Independent Market Monitor for PJM," Docket No. ER15-852-000 (February 13, 2015).

Table 6-2 shows the HHI value for committed UCAP MW by LDA by delivery year. The HHI values are calculated by the committed UCAP MW in each delivery year for demand resources.

Table 6-2 HHI value for committed UCAP MW by LDA by delivery year: 2021/2022 and 2022/2023 Delivery Years[24]

Delivery Year	LDA	Committed UCAP MW	HHI Value	HHI Concentration
2021/2022	ATSI	924.0	2212	High
	ATSI-CLEVELAND	272.8	4800	High
	BGE	279.0	2171	High
	COMED	2,073.7	2492	High
	DAY	227.7	2748	High
	DEOK	220.5	2131	High
	DPL-SOUTH	66.3	4622	High
	EMAAC	904.7	1852	High
	MAAC	750.0	1868	High
	PEPCO	345.9	1995	High
	PPL	697.7	2034	High
	PS-NORTH	188.6	2184	High
	PSEG	221.9	1835	High
	RTO	4,254.9	2462	High
2022/2023	ATSI	757.6	2267	High
	ATSI-CLEVELAND	191.8	2589	High
	BGE	163.9	3049	High
	COMED	1,521.9	2515	High
	DAY	210.5	2709	High
	DEOK	185.1	2354	High
	DPL-SOUTH	48.4	4936	High
	EMAAC	796.9	2157	High
	MAAC	530.5	2185	High
	PEPCO	325.3	3163	High
	PPL	661.7	2143	High
	PS-NORTH	93.8	2613	High
	PSEG	200.8	2060	High
	RTO	3,178.0	2247	High

Market Performance

Table 6-3 shows the cleared Demand Resource UCAP MW by delivery year. Total cleared demand response UCAP MW in PJM decreased by 2,561.5 MW, or 22.4 percent, from 11,427.7 MW in the 2021/2022 Delivery Year to 8,866.2 MW in the 2022/2023 Delivery Year. The DR percent of capacity decreased by 0.6 percentage points, from 6.5 percent in the 2021/2022 Delivery Year to 5.9 percent in the 2022/2023 Delivery Year.

Table 6-3 Cleared Demand Resource UCAP MW: 2007/2008 through 2022/2023 Delivery Year

	UCAP (MW)		
	DR RPM Cleared	Total RPM Cleared	DR Percent Cleared
2007/2008	127.6	129,409.2	0.1%
2008/2009	559.4	130,629.8	0.4%
2009/2010	892.9	134,030.2	0.7%
2010/2011	962.9	134,036.2	0.7%
2011/2012	1,826.6	134,139.6	1.4%
2012/2013	8,740.9	141,061.8	6.2%
2013/2014	10,779.6	159,830.5	6.7%
2014/2015	14,943.0	161,092.4	9.3%
2015/2016	15,453.7	173,487.4	8.9%
2016/2017	13,265.3	179,749.0	7.4%
2017/2018	11,870.5	180,590.3	6.6%
2018/2019	11,435.4	175,957.4	6.5%
2019/2020	10,703.1	177,040.6	6.0%
2020/2021	9,445.7	173,688.5	5.4%
2021/2022	11,427.7	174,713.0	6.5%
2022/2023	8,866.2	150,465.2	5.9%

Table 6-4 shows zonal monthly capacity market revenue to demand resources for January through March 2023. Capacity market revenue decreased in the first three months of 2023 by $101.5 million, 66.3 percent, from $153.0 million in the first three months of 2022 to $51.5 million in the first three months of 2023. The RTO clearing price for the RPM Base Residual Auction for the 2021/2022 Delivery Year was $140.00 per MW-day. The RTO clearing price for the RPM Base Residual Auction for the 2022/2023 Delivery Year was $50.00 per MW-day, 64.2 percent lower than the clearing price for the RTO Base Residual Auction for the 2021/2022 Delivery Year. The capacity revenue amounts for the first three months of 2022 are from the 2021/2022 Delivery Year and the capacity revenue amounts for the first three months of 2023 are from the 2022/2023 Delivery Year.

24 The RTO LDA refers to the rest of RTO.

Table 6-4 Zonal monthly demand resource capacity revenue: January through March, 2023

Zone	January	February	March	Total
ACEC	$188,693	$170,433	$188,693	$547,819
AEP, EKPC	$2,464,810	$2,226,280	$2,464,810	$7,155,900
APS	$1,036,950	$936,600	$1,036,950	$3,010,500
ATSI	$1,447,257	$1,307,200	$1,447,257	$4,201,713
BGE	$639,046	$577,203	$639,046	$1,855,296
COMED	$2,921,684	$2,638,940	$2,921,684	$8,482,307
DAY	$326,275	$294,700	$326,275	$947,250
DOM	$1,156,409	$1,044,498	$1,156,409	$3,357,315
DPL	$467,487	$422,246	$467,487	$1,357,219
DUKE	$411,364	$371,555	$411,364	$1,194,283
DUQ	$230,330	$208,040	$230,330	$668,700
JCPLC	$448,375	$404,984	$448,375	$1,301,734
MEC	$685,062	$618,765	$685,062	$1,988,888
PE	$890,253	$804,100	$890,253	$2,584,607
PECO	$1,105,466	$998,485	$1,105,466	$3,209,417
PEPCO	$470,516	$424,982	$470,516	$1,366,014
PPL	$1,964,912	$1,774,759	$1,964,912	$5,704,583
PSEG	$893,716	$807,228	$893,716	$2,594,660
REC	$4,854	$4,384	$4,854	$14,091
TOTAL	$17,753,458	$16,035,381	$17,753,458	$51,542,296

Product Definition

Pre-Emergency and Emergency Load Response resources must register all resources to respond within 30, 60 or 120 minutes of a PJM dispatched event. This default 30 minute prior notification applies unless a CSP obtains an exception from PJM due to physical operational limitations that prevent the Demand Resource Registration from reducing load within that timeframe.

Table 6-5 shows the amount of nominated MW and locations by product type and lead time for the 2021/2022 Delivery Year. Nominated MW are Pre-Emergency or Emergency Load Response registrations used to satisfy a CSP's committed MW position for a delivery year. PJM approved 3,213 locations, or 20.9 percent of all locations, which have 3,645.6 nominated MW, or 45.8 percent of all nominated MW, for exceptions to the 30 minute lead time rule for the 2021/2022 Delivery Year.

Table 6-5 Nominated MW and locations by product type and lead time: 2021/2022 Delivery Year

Lead Type	Pre-Emergency MW	Emergency MW	Total
Quick Lead (30 Minutes)	4,114.1	203.8	4,317.9
Short Lead (60 Minutes)	285.5	21.0	306.5
Long Lead (120 Minutes)	3,198.2	140.8	3,339.1
Total	7,597.9	365.7	7,963.5
Lead Type	**Pre-Emergency Locations**	**Emergency Locations**	**Total**
Quick Lead (30 Minutes)	11,702	444	12,146.0
Short Lead (60 Minutes)	331	37	368.0
Long Lead (120 Minutes)	2,658	187	2,845.0
Total	14,691	668	15,359.0

Table 6-6 shows the amount of nominated MW and locations by product type and lead time for the 2022/2023 Delivery Year. PJM approved 3,192 locations, or 18.5 percent of all locations, which have 4,095.8 nominated MW, or 47.3 percent of all nominated MW, for exceptions to the 30 minute lead time rule for the 2022/2023 Delivery Year.

Table 6-6 Nominated MW and locations by product type and lead time: 2022/2023 Delivery Year

Lead Type	Pre-Emergency MW	Emergency MW	Total
Quick Lead (30 Minutes)	4,374.2	191.7	4,565.9
Short Lead (60 Minutes)	353.8	21.0	374.8
Long Lead (120 Minutes)	3,574.1	146.9	3,721.0
Total	8,302.2	359.6	8,661.8
Lead Type	**Pre-Emergency Locations**	**Emergency Locations**	**Total**
Quick Lead (30 Minutes)	13,642	389	14,031.0
Short Lead (60 Minutes)	317	36	353.0
Long Lead (120 Minutes)	2,657	182	2,839.0
Total	16,616	607	17,223.0

The only alternative notification times that PJM will permit are 60 minutes and 120 minutes. The CSP must submit in writing that it seeks an exception to permit a prior notification time of 60 minutes or 120 minutes, and the reason(s) for the requested exception. Once a location is granted a longer lead time, the resource does not need to resubmit for a longer lead time each delivery year.

The request for an exception must demonstrate one of four defined reasons:[25]

- The manufacturing processes for the Demand Resource Registration require gradual reduction to avoid damaging major industrial equipment used in the manufacturing process, or damage to the product generated or feedstock used in the manufacturing process;
- Transfer of load to backup generation requires time intensive manual process taking more than 30 minutes;
- Onsite safety concerns prevent location from implementing reduction plan in less than 30 minutes; or,
- The Demand Resource Registration is comprised of mass market residential customers or Small Commercial Customers which collectively cannot be notified of a Load Management Event within 30 minutes due to unavoidable communications latency, in which case the requested notification time shall be no longer than 120 minutes.

Table 6-7 shows the nominated MW and locations by product type and lead time of granted lead time exceptions for the 2022/2023 Delivery Year.[26]

Table 6-7 Nominated MW and locations of granted lead time exceptions: 2022/2023 Delivery Year

	Short Lead (60 Minutes)	Long Lead (120 Minutes)	
Reason	MW	MW	Total
Generation Start Time	53.9	816.1	870.0
Manufacturing Damage	253.3	1,919.6	2,172.9
Safety Problem	67.5	985.4	1,052.9
Total	374.8	3,721.0	4,095.8
	Short Lead (60 Minutes)	Long Lead (120 Minutes)	
Reason	Locations	Locations	Total
Generation Start Time	67	452	519
Manufacturing Damage	207	797	1,004
Safety Problem	79	1,590	1,669
Total	353	2,839	3,192

There are two ways to measure load reductions of demand resources. The Firm Service Level (FSL) method, applied to the summer, measures the difference between a customer's peak load contribution (PLC) and its real-time load, multiplied by the loss factor (LF).[27] The Guaranteed Load Drop (GLD) method measures the minimum of: the comparison load minus real-time load multiplied by the loss factor; or the PLC minus the real-time load multiplied by the loss factor. The comparison load estimates what the load would have been if PJM did not declare a Load Management Event, similar to a CBL, by using a comparable day, same day, customer baseline, regression analysis or backup generation method. Limiting the GLD method to the minimum of the two calculations ensures reductions occur below the PLC, thus avoiding double counting of load reductions.[28] With the introduction of the Winter Peak Load (WPL) concept, effective for the 2017/2018 Delivery Year, both the FSL and GLD methods are modified for the non-summer period. The FSL method measures compliance during the non-summer period as the difference between a customer's WPL multiplied by the Zonal Winter Weather Adjustment Factor (ZWWAF) and the LF, rather than the PLC, and real-time load, multiplied by the LF. PJM calculates and posts on the PJM website the ZWWAF as the zonal winter weather normalized peak divided by the zonal average of the five coincident peak loads in December through February.[29] The Winter Peak Load is adjusted up for transmission and distribution line loss factors because one MW of load would be served by more than one MW of generation to account for transmission losses. The Winter Peak Load is normalized based on the winter conditions during the five coincident peak loads in winter using the ZWWAF to account for an extreme temperatures or a mild winter. The GLD method measures compliance during the non-summer period as the minimum of: the comparison load minus real-time load multiplied by the loss factor; or the WPL multiplied by the ZWWAF and the LF, rather than the PLC, minus the real-time load multiplied by the LF.[30]

The capacity market is an annual market. A Capacity Performance resource has an annual commitment. Effective with the 2020/2021 Delivery Year, the capacity market design includes the ability to offer Seasonal Capacity Performance Resources directly into the RPM Auction as an alternative to entering into a commercial arrangement to establish and offer an Aggregate Resource. Capacity Market Sellers may submit sell offers of either Summer

25 OATT Attachment DD-1, Section A.2(a).
26 Data for generation start time and mass market communication categories were combined based on confidentiality rules.
27 Real-time load is hourly metered load.
28 135 FERC ¶ 61,212 (2011).
29 "PJM Manual 18: PJM Capacity Market," § 4.3.7, Rev. 55 (Feb. 9, 2023).
30 "PJM Manual 18: PJM Capacity Market," § 8.7A, Rev. 55 (Feb. 9, 2023).

Period Capacity Performance Resources or Winter Period Capacity Performance Resources and the auction clearing optimization algorithm is designed to clear equal quantities of offsetting seasonal capacity sell offers thereby creating an annual capacity commitment by matching a Summer Period Capacity Performance Resource with a Winter Period Capacity Performance Resource. Load is allocated capacity obligations based on the annual peak load which is a summer load. The amount of capacity MW allocated to load does not vary based on winter demand. The principle is that a customer's actual use of capacity should be compared to the level of capacity that a customer is required to pay for. Capacity costs are allocated to LSEs by PJM based on the single coincident peak load method. In PJM, the single coincident peak occurs in the summer.[31] LSEs generally allocate capacity costs to customers based on the five coincident peak method.[32] The allocation of capacity costs to customers uses each customer's PLC. Customers pay for capacity based on the PLC, not the WPL. If an end customer has 3 MW of load during the coincidental peak load hour, but only 1 MW during the coincidental winter peak load hour, the end use customer must pay for 3 MW of capacity for the entire delivery year, but can only participate as a 1 MW demand response resource. Using PLC to measure compliance the entire delivery year would allow the customer to fully participate as a 3 MW demand response resource. FERC allowed the use of the WPL for calculating compliance for non-summer months effective June 1, 2017.[33] The MMU recommends setting the baseline for measuring capacity compliance under summer and winter compliance at the customer's PLC, similar to GLD, to avoid double counting, to avoid under counting and to ensure that a customer's purchase of capacity is calculated correctly. The FSL and GLD equations for calculating load reductions are:

$$FSL\ Compliance_{Summer} = PLC - (Load \cdot LF)$$

$$FSL\ Compliance_{Non-Summer} = (WPL \cdot ZWWAF \cdot LF) - (Load \cdot LF)$$

$$GLD\ Compliance_{Summer} = Minimum\{(comparison\ load - Load) \cdot LF; PLC - (Load \cdot LF)\}$$

$$\begin{aligned} GLD\ Compliance_{Non-Summer} \\ &= Minimum\{(comparison\ load - Load) \cdot LF; (WPL \cdot ZWWAF \cdot LF) \\ &- (Load \cdot LF)\} \end{aligned}$$

Table 6-8 shows the MW registered by measurement and verification method and by technology type for the 2022/2023 Delivery Year. For the 2022/2023 Delivery Year, 99.98 percent use the FSL method and 0.02 percent use the GLD measurement and verification method.

Table 6-8 Nominated MW by each demand response method: 2022/2023 Delivery Year

	Technology Type								
Measurement and Verification Method	On-site Generation MW	HVAC MW	Refrigeration MW	Lighting MW	Manufacturing MW	Water Heating MW	Other, Batteries or Plug Load MW	Total	Percent by type
Firm Service Level	1,251.2	2,152.0	189.7	757.3	4,238.4	22.8	48.4	8,659.9	99.98%
Guaranteed Load Drop	0.3	1.5	0.0	0.0	0.1	0.0	0.0	1.8	0.02%
Total	1,251.4	2,153.5	189.7	757.3	4,238.5	22.8	48.4	8,661.8	100.0%
Percent by method	14.4%	24.9%	2.2%	8.7%	48.9%	0.3%	0.6%	100.0%	

31 OATT Attachment DD.5.11.
32 OATT Attachment M-2.
33 162 FERC ¶ 61,159 (2018).

Table 6-9 shows the fuel type used in the onsite generators for the 2022/2023 Delivery Year in the emergency and pre-emergency programs. For the 2022/2023 Delivery Year, 1,251.4 MW of the 8,661.8 nominated MW, 14.4 percent, used onsite generation. Of the 1,251.4 MW, 83.4 percent used diesel and 16.6 percent used natural gas, gasoline, oil, propane or waste products.

Table 6-9 Onsite generation fuel type (MW): 2022/2023 Delivery Year

	2022/2023	
Fuel Type	MW	Percent
Diesel	1,043.2	83.4%
Natural Gas, Gasoline, Oil, Propane, Waste Products	208.3	16.6%
Total	1,251.4	100.0%

Table 6-10 shows the MW registered by measurement and verification method and by technology type for the 2021/2022 Delivery Year. For the 2021/2022 Delivery Year, 99.98 percent use the FSL method and 0.02 percent use the GLD measurement and verification method.

Table 6-10 Nominated MW by each demand response method: 2021/2022 Delivery Year

	Technology Type								
Measurement and Verification Method	On-site Generation MW	HVAC MW	Refrigeration MW	Lighting MW	Manufacturing MW	Water Heating MW	Batteries and Plug Load MW	Total	Percent by type
Firm Service Level	1,232.2	1,911.6	191.1	666.3	3,903.7	17.2	39.9	7,962.0	99.98%
Guaranteed Load Drop	0.3	1.0	0.0	0.0	0.0	0.0	0.3	1.5	0.02%
Total	1,232.5	1,912.6	191.1	666.3	3,903.7	17.2	40.1	7,963.5	100.0%
Percent by method	15.5%	24.0%	2.4%	8.4%	49.0%	0.2%	0.5%	100.0%	

Table 6-11 shows the fuel type used in the onsite generators for the 2021/2022 Delivery Year in the emergency and pre-emergency programs. For the 2021/2022 Delivery Year, 1,232.5 MW of the 7,963.5 nominated MW, 15.5 percent, use onsite generation. Of the 1,232.5 MW, 83.5 percent use diesel and 16.5 percent use natural gas, gasoline, oil, propane or waste products.

Table 6-11 Onsite generation fuel type (MW): 2021/2022 Delivery Year

	2021/2022	
Fuel Type	MW	Percent
Diesel	1,029.2	83.5%
Natural Gas, Gasoline, Oil, Propane, Waste Products	203.2	16.5%
Total	1,232.5	100.0%

Emergency and Pre-Emergency Event Reported Compliance

Capacity resources measure performance nodally, except for demand resources. PJM cannot dispatch demand resources by node with the current rules because demand resources are not registered to a node. Demand resources can be dispatched by subzone only if the subzone is defined before dispatch. Aggregation rules allow a demand resource that incorporates many small end use customers to span an entire zone, which is inconsistent with nodal dispatch.

Subzonal dispatch became mandatory for emergency demand resources in the 2014/2015 Delivery Year, if the subzone was defined by PJM no later than the day before the dispatch.[34] With the full implementation of the Capacity Performance rules in the 2020/2021 Delivery Year, the requirement that subzones be defined one day prior to dispatch is no longer in effect. A subzone is defined by zip code, not by nodal location. If a registration has any location in the dispatched subzone, as defined by the zip code of the enrolled end use customer's address, the entire registration must respond. Subzonal dispatch creates a PAI for the subzone, even if PJM does not measure compliance for demand resources. There are currently seven defined dispatchable subzones in PJM: APS_EAST, DOM_CHES, DOM_YORKTOWN, AECO_ENGLAND, JCPL_REDBANK, DOM_ASHBURN and AEP_MARION.[35] The AEP_MARION subzone was added as a result of the June 14-16, 2022, performance assessment event in the Columbus, Ohio area of the AEP Zone.

34 OATT Attachment DD, Section 11.
35 See "Load Management Subzones," <https://www.pjm.com/-/media/markets-ops/demand-response/subzone-definition-workbook.ashx> (Accessed January 13, 2023).

PJM can remove a defined subzone, and make changes to the subzone, at their discretion. Subzones should not be removed once defined, as the subzone may need to be dispatched again in the future. The METED_EAST, PENELEC_EAST, PPL_EAST and DOM_NORFOLK Subzones were removed by PJM. More subzones may have been removed by PJM but PJM does not keep a record of created and removed subzones. The MMU recommends that PJM not remove any defined subzones and maintain a public record of all created and removed subzones. The MMU recommends that, if PJM continues to use subzones for any purpose, PJM clearly define the role of subzones in the dispatch of demand response.

The subzone design and closed loop interfaces are related. PJM implemented closed loop interfaces with the stated purpose of improving the incorporation of reactive constraints into energy prices and to allow emergency DR to set price.[36] PJM applies closed loop interfaces so that it can use units needed for reactive support to set the energy price when they would not otherwise set price under the LMP algorithm. PJM also applies closed loop interfaces so that it can use emergency DR resources to set the real-time LMP when DR would not otherwise set price under the fundamental LMP logic. Of the 20 closed loop interface definitions, 11 (55 percent) were created for the purpose of allowing emergency DR to set price.[37] The closed loop interfaces created for the purpose of allowing emergency DR to set price are located in the Rest of RTO, MAAC, EMAAC, SWMAAC, DPL-SOUTH, ATSI, ATSI-CLEVELAND and BGE LDAs. These interfaces correspond to LDAs as defined in RPM.[38]

Demand resources can be dispatched for voluntary compliance during any hour of any day, but dispatched resources are not measured for compliance outside of the mandatory compliance window for each demand product. A demand response event during a product's mandatory compliance window also may not result in a compliance score. When demand response events occur for partial hours under 30 minutes, the event is not measured for compliance.

36 See PJM/Alstom. "Approaches to Reduce Energy Uplift and PJM Experiences," presented at the FERC Technical Conference: Increasing Real-Time and Day-Ahead Market Efficiency Through Improved Software, Docket No. AD10-12-006 (June 23, 2015) <http://www.ferc.gov/june-tech-conf/2015/presentations/m2-3.pdf>.

37 See the *2018 State of the Market Report for PJM*, Volume 2, Section 4, Energy Uplift, for additional information regarding all closed loop interfaces and the impacts to the PJM markets.

38 "PJM Manual 18: PJM Capacity Market," § 2.3.1, Rev. 55 (Feb. 9, 2023).

Demand resources currently estimate five minute compliance with an hourly interval meter during PAIs. To accurately measure compliance on a five minute basis, a five minute interval meter is required. All other capacity resources require five minute interval meters, and demand resources should be no different. Demand resources are paid based on the average performance by registration for the duration of a demand response event. Demand response should measure compliance on a five minute basis to accurately report reductions during demand response events. Measuring compliance on a five minute basis would provide accurate information to the PJM system. The MMU recommends demand response event compliance be calculated on a five minute basis for all capacity resources and that the penalty structure reflect five minute compliance.[39]

Under the capacity performance design of the PJM Capacity Market, compliance for potential penalties will be measured for DR only during performance assessment intervals (PAI).[40] When pre-emergency or emergency demand response is dispatched, a PAI is triggered for PJM. PJM cannot dispatch pre-emergency or emergency demand response without triggering a PAI and measuring compliance. Before PJM created PAI to measure compliance, pre-emergency demand response could be dispatched without calling an emergency event. As a result, PJM now effectively classifies all demand response as an emergency resource.

The MMU recommends that demand response resources be treated as economic resources like all other capacity resources and therefore that the dispatch of demand response resources not automatically trigger a performance assessment interval (PAI) for CP compliance. Emergencies should be triggered only when PJM has exhausted all economic resources including demand response resources. Table 6-12 shows the amount of nominated demand response MW, the required reserve margin and actual reserve margin for the 2021/2022 and 2022/2023 Delivery Years. There are 8,129.7 nominated MW of demand response for the 2022/2023 Delivery Year, 45.2 percent of the required reserve margin and 33.1 percent of the actual reserve margin for the 2022/2023 Delivery Year.[41]

39 "PJM Manual 18: PJM Capacity Market," § 8.7A, Rev. 55 (Feb. 9, 2023).

40 OATT § 1 (Performance Assessment Hour).

41 *2022 Annual State of the Market Report for PJM*, Section 5: Capacity Market, Table 5-7.

Table 6-12 Demand response nominated MW compared to reserve margin: 2021/2022 and 2022/2023 Delivery Years[42]

Delivery Year	Demand Response Nominated MW	Required Reserve Margin	Demand Response Percent of Required Reserve Margin	Actual Reserve Margin	Demand Response Percent of Actual Reserve Margin
2021/2022	10,512.1	20,176.5	52.1%	28,005.0	37.5%
2022/2023	8,129.7	17,990.4	45.2%	24,586.6	33.1%

PJM will dispatch demand resources by zone or subzone for demand resources, or within a PAI area for Capacity Performance resources. When PJM dispatches all demand resources in multiple connecting zones, PJM further degrades the nodal design of electricity markets. PJM allows compliance to be measured across zones within a compliance aggregation area (CAA) or Emergency Action Area (EAA).[43] [44] A CAA, or EAA, is an electrically connected area that has the same capacity market price. This changes the way CSPs dispatch resources when multiple electrically contiguous areas with the same RPM clearing prices are dispatched. The compliance rules determine how CSPs are paid and thus create incentives that CSPs will incorporate in their decisions about how to respond to PJM dispatch. The multiple zone approach is even less locational than the zonal and subzonal approaches and creates larger mismatches between the locational need for the resources and the actual response. If multiple zones within a CAA are called by PJM, a CSP will dispatch the least cost resources across the zones to cover the CSP's obligation. This can result in more MW dispatched in one zone that are locationally distant from the relief needed and no MW dispatched in another zone, yet the CSP could be considered 100 percent compliant and pay no penalties. More locational deployment of load management resources would improve efficiency. With full implementation of capacity performance, demand response will be dispatched by registrations within an area for which an Emergency Action is declared by PJM. PJM does not have the nodal location of each registration, meaning PJM will need to guess as to the useful demand response registration by registered location. The MMU recommends that demand resources be required to provide their nodal location. Nodal dispatch of demand resources would be consistent with the nodal dispatch of generation.

42 Nominated MW totals are Demand Response ICAP corresponding to Demand Response UCAP cleared in RPM auctions for each delivery year. The total nominated MW values do not reflect replacement transactions.

43 CAA is "a geographic area of Zones or sub-Zones that are electrically contiguous and experience for the relevant Delivery Year, based on Resource Clearing Prices of, for Delivery Years through May 31, 2018, Annual Resources and for the 2018/2019 Delivery Year and subsequent Delivery Years, Capacity Performance Resources, the same locational price separation in the Base Residual Auction, the same locational price separation in the First Incremental Auction, the same locational price separation in the Second Incremental Auction, or the same locational price separation in the Third Incremental Auction." OATT § 1.

44 PJM. "Manual 18: Capacity Market," § 8.7.2, Rev. 55 (Feb. 9, 2023).

Definition of Compliance

PJM's reporting of load management events overstates performance of demand side capacity resources. Limiting reported compliance to only positive values incorrectly reports compliance. Settlement locations with a negative load reduction value (load increase) are not included in compliance reporting by PJM within registrations or within demand response portfolios. A resource that has load above their PLC during a demand response event has a negative performance value. PJM limits reported compliance shortfall values to zero MW.

The MMU recommends that PJM correctly report compliance for demand side capacity resources to include negative values above PLC when calculating event compliance across hours and registrations.

Demand resources that are also registered as economic resources have a calculated CBL for the emergency event days. Demand resources that are not registered as Economic Resources use the three day CBL type with the symmetrical additive adjustment for measuring energy reductions without the requirements of a Relative Root Mean Squared Error (RRMSE) Test required for all economic resources.[45] The CBL must use the RRMSE test to verify that it is a good approximation for real-time load usage.

The MMU recommends that PJM Manual 11 be revised to require, rather than recommend, that the RRMSE test be applied to all demand resources with a CBL.[46]

The CBL for a customer is an estimate of what load would have been if the customer had not responded to LMP and reduced load. The difference between the CBL and real-time load is the energy reduction. When load responds to LMP by using a behind the meter generator, the energy reduction should be capped at the generation output. Any additional energy reduction is a result of inaccuracy in the CBL estimate rather than an actual reduction. The MMU

45 157 FERC ¶ 61,067 (2016).

46 PJM. "Manual 11: Energy & Ancillary Services Market Operations," § 10.2.5, Rev. 123 (Feb. 9, 2023).

recommends capping demand reductions based entirely on behind the meter generation at the lower of economic maximum or actual generation output.

An extreme example makes clear the fundamental problems with the use of measurement and verification methods to define the level of power that would have been used but for the DR actions, and the payments to DR customers that result from these methods. The current rules for measurement and verification for demand resources make a bankrupt company, a customer that no longer exists due to closing of a facility or a permanently shut down company, or a company with a permanent reduction in peak load due to a partial closing of a facility, an acceptable demand response customer under some interpretations of the tariff, although it is the view of the MMU that such customers should not be permitted to be included as registered demand resources. Companies that remain in business, but with a substantially reduced load, can maintain their pre-bankruptcy FSL (firm service level to which the customer agrees to reduce in an event) commitment, which can be greater than or equal to the post-bankruptcy peak load. The customer agrees to reduce to a level which is greater than or equal to its new peak load after bankruptcy. When demand response events occur the customer would receive credit for 100 percent reduction, even though the customer took no action and could take no action to reduce load. This problem exists regardless of whether the customer is still paying for capacity. To qualify and participate as a demand resource, the customer must have the ability to reduce load. "A participant that has the ability to reduce a measurable and verifiable portion of its load, as metered on an EDC account basis."[47] Such a customer no longer has the ability to reduce load in response to price or a PJM demand response event. CSPs in PJM have and continue to register bankrupt customers as emergency or pre-emergency load response customers. PJM finds acceptable the practice of CSPs maintaining the registration of customers with a bankruptcy related reduction in demand that are unable, as a result, to respond to emergency events. Three proposals that included language to remove bankrupt customers from a CSP's portfolio failed at the June 7, 2017, Market Implementation Committee.[48] The registered customers that are bankrupt and the amount of registered MW cannot be released for reasons of confidentiality.

The metering requirement for demand resources is outdated, and has not kept up with the changes to PJM's market design. PJM moved to five minute settlements, but the metering requirement for demand resources remained at an hourly interval meter. It is impossible to measure energy usage on a five minute basis using an hourly interval meter. PJM will estimate real-time usage by prorating the hourly interval meter and assume if load is less than the CBL, that the reduction occurred during the required dispatch window. The meter reading is not telemetered to PJM in real time. The resource is allowed up to 60 days to report the data to PJM. The MMU recommends that PJM adopt the ISO-NE five-minute metering requirements in order to ensure that dispatchers have the necessary information for reliability and that market payments to demand resources be calculated based on interval meter data at the site of the demand reductions so that they can accurately measure compliance.[49]

When demand resources are not dispatched during a mandatory response window, each CSP must test their portfolio to the levels of capacity commitment, but the testing requirements are inadequate.[50] The CSP must notify PJM of the intent to test 48 hours in advance of the test. A notification of intent to test must be submitted in the DR Hub system. If a CSP failed to provide the required load reduction in a zone by less than 25 percent of their Summer Average RPM Commitment in the zone, the CSP may conduct a retest of the subset of registrations in the zone that failed. If the CSP elects to not retest a subset of registrations that failed the test, such registrations will maintain the compliance result achieved in the initial test. Retesting must be performed at the same time of day and under approximately the same weather conditions. Multiple tests may be conducted; however, only one test result may be submitted for each end use customer site in the DR Hub System for

47 OA Schedule 1 § 8.2.

48 There was one proposal from PJM, one proposal from a market participant and one proposal from the MMU. See *Approved Minutes from the Market Implementation Committee*, <http://www.pjm.com/-/media/committees-groups/committees/mic/20170607/20170607-minutes.ashx>.

49 See ISO-NE Tariff, Section III, Market Rule 1, Appendix E1 and Appendix E2, "Demand Response," <http://www.iso-ne.com/regulatory/tariff/sect_3/mr1_append-e.pdf>. (Accessed October 17, 2017) ISO-NE requires that DR have an interval meter with five-minute data reported to the ISO and each behind the meter generator is required to have a separate interval meter. After June 1, 2017, demand response resources in ISO-NE must also be registered at a single node.

50 The mandatory response time for Capacity Performance DR is June through October and the following May between 10:00AM to 10:00PM EPT and November through April between 6:00AM through 9:00PM EPT. *See* PJM. "Manual 18: PJM Capacity Market," Rev. 55 (Feb. 9, 2023).

compliance evaluation. Test data must be submitted on or after June 1st and no later than July 14th after the start of the delivery year.

The ability of CSPs to pick the test time does not simulate emergency conditions. As a result, test compliance is not an accurate representation of the capability of the resource to respond to an actual PJM dispatch of the resource. Given that demand resources are now an annual product, multiple tests are required to ensure reduction capability year round. The MMU recommends that load management testing be initiated by PJM with limited warning to CSPs in order to more accurately represent the conditions of an emergency event.

Table 6-13 shows the test penalties by delivery year by product type for the 2016/2017 Delivery Year through the 2021/2022 Delivery Year.[51] The shortfall MW are calculated for each CSP by zone. The weighted rate per MW is the average penalty rate paid per MW. The total penalty column is the sum of the daily test penalties by delivery year and type. Total Load Management Test Compliance penalties were 0.36 percent of total DR revenues in the 2021/2022 Delivery Year.

Table 6-13 Test penalties by delivery year by product type: 2016/2017 through 2021/2022

	2016/2017			2017/2018			2018/2019			2019/2020			2020/2021			2021/2022		
Product Type	Shortfall MW	Weighted Rate per MW	Total Penalty	Shortfall MW	Weighted Rate per MW	Total Penalty	Shortfall MW	Weighted Rate per MW	Total Penalty	Shortfall MW	Weighted Rate per MW	Total Penalty	Shortfall MW	Weighted Rate per MW	Total Penalty	Shortfall MW	Weighted Rate per MW	Total Penalty
Limited	48.9	$166.41	$2,967,158	13.9	$124.08	$631,665	0.03	$179.80	$2,100									
Extended Summer	7.3	$138.14	$370,290	10.5	$142.86	$547,928												
Annual	4.8	$137.45	$241,406	16.3	$144.00	$855,940												
Base DR and EE							16.3	$186.80	$1,110,134	30.2	$154.69	$1,712,177						
Capacity Performance	2.1	$160.80	$124,310	0.6	$181.80	$40,146	2.6	$188.55	$178,795				0.9	$125.30	$39,422	23.1	$176.79	$1,487,430
Total	63.1	$160.72	$3,703,163	41.3	$137.54	$2,075,678	18.9	$187.03	$1,291,030	30.2	$154.69	$1,712,177	0.9	$125.30	$39,422	23.1	$176.79	$1,487,430

51 Not all products received penalties or existed in every delivery year. For example, the Base and Capacity Performance products were not an option for the 2020/2021 Delivery Year.

Emergency and Pre-Emergency Load Response Energy Payments

Emergency and pre-emergency demand response dispatched during a load management event by PJM are eligible to receive emergency energy payments if registered under the full program option. The full program option includes an energy payment for load reductions during a pre-emergency or emergency event for demand response events and capacity payments.[52] There are 98.1 percent of nominated MW for the 2022/2023 Delivery Year registered under the full program option. There are 1.9 percent of nominated MW for the 2022/2023 Delivery Year registered as capacity only option. Demand resources clear the capacity market like all other capacity resources and the dispatch of demand resources should not trigger a scarcity event. The strike price is set by the CSP before the delivery year starts and cannot be changed during the delivery year. The demand resource energy payments are equal to the higher of hourly zonal LMP or a strike price energy offer made by the participant, including a dollar per MWh minimum dispatch price and an associated shutdown cost. Demand resources should not be permitted to offer above $1,000 per MWh without cost justification or to include a shortage penalty in the offer. FERC has stated clearly that demand resources in the capacity market must verify costs above $1,000 per MWh, unless they are capacity only: "We clarify, however, that reforms adopted in this Final Rule, which provide that resources are eligible to submit cost-based incremental energy offers in excess of $1,000/MWh and require that those offers be verified, do not apply to capacity-only demand response resources that do not submit

52 *Id.*

incremental energy offers in energy markets."[53] PJM interprets the scarcity pricing rules to allow a maximum DR energy price of $1,849 per MWh for the 2021/2022 Delivery Year.[54] [55] Demand resources registered with the full option should be required to verify energy offers in excess of $1,000 per MWh. PJM does not require such verification.[56] The MMU recommends that the maximum offer for demand resources be the same as the maximum offer for generation resources.

Shutdown costs for demand response resources are not adequately defined in Manual 15. PJM's Cost Development Subcommittee (CDS) approved changes to Manual 15 to eliminate shutdown costs for demand response resources participating in the synchronized reserve market, but not demand resources or economic resources.[57]

Table 6-14 shows the distribution of registrations and associated MW in the emergency full option across ranges of minimum dispatch prices for the 2021/2022 Delivery Year. The majority of participants, 77.3 percent of locations and 52.1 percent of nominated MW, had a minimum dispatch price between $1,550 and $1,849 per MWh, the maximum price allowed for the 2021/2022 Delivery Year. Almost all registrations, 99.3 percent of locations and 97.3 percent of nominated MW have a dispatch price above $1,000 per MWh. The shutdown cost of resources with $1,000 to $1,275 per MWh strike prices had the highest average at $166.11 per location and $150.48 per nominated MW.

Table 6-14 Distribution of registrations and associated MW in the full option across ranges of minimum dispatch: 2021/2022 Delivery Year

Ranges of Strike Prices ($/MWh)	Locations	Percent of Total	Nominated MW (ICAP)	Percent of Total	Shutdown Cost per Location	Shutdown Cost Per Nominated MW (ICAP)
$0-$1,000	107	0.7%	207.8	2.7%	$97.45	$50.19
$1,000-$1,275	2,912	19.5%	3,214.4	41.4%	$166.11	$150.48
$1,275-$1,550	367	2.5%	295.3	3.8%	$44.06	$54.75
$1,550-$1,849	11,511	77.3%	4,046.8	52.1%	$50.83	$144.59
Total	14,897	100.0%	7,764.4	100.0%	$73.53	$141.09

Table 6-15 shows the distribution of registrations and associated MW in the emergency full option across ranges of minimum dispatch prices for the 2022/2023 Delivery Year. The majority of participants, 80.3 percent of locations and 51.7 percent of nominated MW, have a minimum dispatch price between $1,550 and $1,849 per MWh, the maximum price allowed for the 2022/2023 Delivery Year. Almost all registrations, 99.3 percent of locations and 97.8 percent of nominated MW have a dispatch price above $1,000 per MWh. The shutdown cost of resources with $1,000 to $1,275 per MWh strike prices have the highest average at $163.04 per location and $132.39 per nominated MW.

Table 6-15 Distribution of registrations and associated MW in the full option across ranges of minimum dispatch: 2022/2023 Delivery Year

Ranges of Strike Prices ($/MWh)	Locations	Percent of Total	Nominated MW (ICAP)	Percent of Total	Shutdown Cost per Location	Shutdown Cost Per Nominated MW (ICAP)
$0-$1,000	119	0.7%	187.1	2.2%	$80.65	$51.31
$1,000-$1,275	2,854	16.9%	3,514.7	41.7%	$163.04	$132.39
$1,275-$1,550	352	2.1%	370.9	4.4%	$42.65	$40.48
$1,550-$1,849	13,523	80.3%	4,353.4	51.7%	$41.89	$130.13
Total	16,848	100.0%	8,426.1	100.0%	$62.71	$125.38

PRD

Price Responsive Demand, or PRD, in the capacity market is capacity based on a firm commitment to reduce load in response to a defined level of real-time energy prices. A PRD offer is a commitment to reduce energy usage by a defined amount in response to real time energy prices during the delivery year. A PRD offer includes MW quantities that the seller will reduce at defined capacity market reservation prices ($/MW-day). PRD offers change the shape of the VRR Curves used in the capacity market auctions.

PRD is provided by a PJM member that represents retail customers that have the ability to reduce load in response to price. In order to be eligible as PRD, the end use customer load must be served under a dynamic retail rate or contractual arrangement linked to, or based upon, a PJM real-time LMP trigger at a substation as electrically close as practical to the applicable load.

53 161 FERC ¶ 61,153 at P 8 (2017).
54 139 FERC ¶ 61,057 (2012).
55 FERC accepted proposed changes to have the maximum strike price for 30 minute demand response to be $1,000/MWh + 1*Shortage penalty - $1.00, for 60 minute demand response to be $1,000/MWh + (Shortage Penalty/2) and for 120 minute demand response to be $1,100/MWh from ER14-822-000.
56 OATT Attachment K Appendix Section 1.10.1A Day-Ahead Energy Market Scheduling (d) (x).
57 "PJM Manual 15: Cost Development Guidelines," § 8.1, Rev. 42 (Oct. 28, 2022).

End use customer loads identified may not sell any other form of demand side management in PJM markets.

PRD must also be curtailed once PJM has declared a Performance Assessment Interval but only if the real-time LMP at the applicable location meets or exceeds the price on the submitted PRD curve at which the load has committed to curtail. The high PRD strike prices mean that PRD could avoid a performance requirement even during a PAI.

In order to commit PRD for a delivery year, a PRD Provider must submit a PRD Plan in advance of the Base Residual Auction which indicates the Nominal PRD Value in MW that the PRD Provider is willing to commit at different reservation prices expressed in ($/MW-day). Additional PRD may participate in the Third Incremental Auction only if the LDA final peak load forecast for the delivery year increases relative to the LDA preliminary peak load forecast used for the Base Residual Auction.

Unlike other capacity resources, once committed, PRD may not be uncommitted or replaced by available capacity resources or Excess Commitment Credits. A PRD Provider may transfer the PRD obligation to another PRD Provider bilaterally. The PRD Provider will receive a Daily PRD Credit ($/MW-day) during the delivery year. A PRD Provider under the FRR Alternative will not be eligible to receive a Daily PRD Credit ($/MW-day) during the delivery year. PRD first cleared the capacity market in the BRA for the 2020/2021 Delivery Year, and has cleared auctions for the 2021/2022 Delivery Year and 2022/2023 Delivery Year.[58] Table 6-16 shows the Nominated MW of Price Responsive Demand for the 2021/2022 and 2022/2023 Delivery Years.

Table 6-16 Nominated MW of price responsive demand: 2021/2022 and 2022/2023 Delivery Years

Delivery Year	RTO	MAAC	EMAAC	SWMAAC	DPL SOUTH	PEPCO	BGE
2022/2023	230.0	230.0	40.0	190.0	19.6	110.0	80.0
2021/2022	510.0	510.0	75.0	435.0	35.7	195.0	240.0

PRD is included on the supply side of RPM auctions. The cleared PRD is credited the adjusted zonal clearing price of the LDA in which they cleared. The PRD credits are charged to the load of those LDAs by inclusion in the RPM net load price A PRD Provider receives a PRD Credit for each approved Price Responsive Demand registration on a given day. PRD Credits are determined as:[59]

*PRD Credit = [(Share of Zonal Nominal PRD Value committed in Base Residual Auction * (Zonal Weather-Normalized Peak Load for the summer concluding prior to the commencement of the Delivery Year / Final Zonal Peak Load Forecast for the Delivery Year) * Final Zonal RPM Scaling Factor * FPR * Final Zonal Capacity Price) plus,*

*(Share of Zonal Nominal PRD Value committed in Third Incremental Auction * (Zonal Weather-Normalized Peak Load for the summer concluding prior to the commencement of the Delivery Year / Final Zonal Peak Load Forecast for the Delivery Year) * Final Zonal RPM Scaling Factor * FPR * Final Zonal Capacity Price * Third Incremental Auction Component of Final Zonal Capacity Price stated as a Percentage)].*

Effective with the 2022/2023 Delivery Year, the factor equal to (Zonal Weather-Normalized Peak Load for the summer concluding prior to the commencement of the Delivery Year / Final Zonal Peak Load Forecast for the Delivery Year) is eliminated in the calculation of the PRD Credit.

Table 6-17 shows the PRD Credits for the 2020/2021 and 2021/2022 Delivery Years.

Table 6-17 PRD Credits for 2020/2021 and 2021/2022 Delivery Years

Delivery Year	PRD Credit
2021/2022	$38,282,769.14
2020/2021	$23,649,865.05

58 There were a total of 558 MW of cleared PRD in the 2020/2021 Delivery Year. See PJM Auction Results, <https://www.pjm.com/-/media/markets-ops/rpm/rpm-auction-info/2020-2021-base-residual-auction-results.ashx?la=en>.

59 PJM. "Manual 18: Capacity Market," § 9.4.4, Rev. 55 (Feb. 9, 2023).

A PRD Provider with a daily commitment compliance shortfall in a subzone/zone for RPM or FRR is assessed a Daily PRD Commitment Compliance Penalty. The Daily PRD Commitment Compliance Penalty is determined as:

*PRD Commitment Compliance Penalty = MW shortfall in the Sub-zone/ Zone * Delivery Year Forecast Pool Requirement * PRD Commitment Compliance Penalty Rate*

The revenue collected from assessment of the PRD Commitment Compliance Penalty is distributed to all entities that committed Capacity Resources in the RPM Auctions for the relevant delivery ear, based on each entity's prorata share of daily revenues from Capacity Market Clearing Prices in such auctions, net of any daily compliance charges incurred by such entity.

Table 6-18 shows the PRD Commitment Compliance Penalties for the 2020/2021 and 2021/2022 Delivery Years

Table 6-18 PRD Commitment Compliance Penalties for 2020/2021 and 2021/2022 Delivery Years

Delivery Year	Charges
2021/2022	$395,319.95
2020/2021	$0

PRD committed in RPM for the current delivery year bids in the PJM Energy Market. PRD Curves may be submitted by PRD Providers in the PJM Energy Market by 1100 at the closing of the day-ahead bid period. PRD Curves submitted by PRD Providers are identified in the day-ahead market software and user interface. PRD bids are modeled in the real-time energy market only, and are modeled in the real-time dispatch algorithms. PRD curves are not modeled in the day-ahead market clearing process. PRD Curves in the energy market are modeled in the real-time dispatch algorithms and can set Real-time LMP. PRD Providers with committed PRD are required to have automation of PRD that is needed to respond to real-time LMPs for the PRD Curves that are submitted. The maximum bid price of the PRD Curve is the applicable energy market offer cap. When PRD sellers offer at the cap, they limit the number of times that PRD is called on to respond.

The PRD rules fall short of defining an effective and efficient product that is aligned with the definition of a capacity resource.[60] PJM's initial filing was rejected by the Commission based on the MMU's comments and PJM's modified filing was accepted.[61] PJM's final filing adopted the MMU's recommendation to exclude the use of Winter Peak Load (WPL) when calculating the nominated MW for PRD resources used to satisfy RPM commitments. Load is allocated capacity obligations based on the annual peak load within PJM. The amount of capacity allocated to load is a function solely of summer coincident peak demand and is unaffected by winter demand. Use of the WPL to calculate the nominated MW for PRD resources to satisfy RPM commitments, would incorrectly restrict PRD to less than the total capacity the customer is required to buy. PJM's adoption of the MMU recommendation correctly values PRD nominated MW. FERC required and PJM's filing also adopted the MMU's recommendation that PRD should be eligible for bonus performance payments during Performance Assessment Intervals (PAI) only when PRD resources respond above their nominated MW value. Allowing PRD resources to collect bonus payments at times when they are not even required to meet their basic obligation would be inconsistent with the basic CP construct as it applies to all other CP resources.[62]

PJM's filing still fell short of completely aligning PRD with the definition of capacity. PRD resources do not have to respond during a PAI if the PRD's trigger price is above LMP during the PAI. All other CP resources have the obligation to perform during a PAI, regardless of the real-time LMP, subject to instructions from PJM. PRD should be held to the same standard during a PAI event. The MMU recommends that PRD be required to respond during a PAI, regardless of whether the real-time LMP at the applicable location meet or exceeds the PRD strike price, to be consistent with all CP resources.

60 See "Compliance Filing Regarding Price Responsive Demand Rules," Docket No. ER20-271-001 (February 28, 2020).
61 See "Order Rejecting Tariff Revisions," Docket No. ER19-1012-000 (June 27, 2019).
62 October 31 Filing, Attachment B, Proposed Revised OATT § 10A (c).

Economic Load Response Program

The Economic Load Response Program is for demand response customers that offer into the day-ahead or real-time energy market. The estimated load reduction is paid the zonal LMP, as long as the zonal LMP is greater than the monthly Net Benefits Test threshold.

Market Structure

Table 6-19 shows the average hourly HHI for each month and the average hourly HHI for January 1, 2022, through February 28, 2023. The ownership of economic demand response resources was highly concentrated in the first two months of 2022 and the first two months of 2023.[63] Table 6-19 lists the share of reported reductions provided by, and the share of credits claimed by the four largest CSPs in each year. The HHI for economic demand response was highly concentrated in the first two months of 2023. The HHI for economic demand response in the first two months of 2023 increased by 1528, 20.4 percent, from 7861 in the first two months of 2022 to 9459 in the first two months of 2023.

Table 6-19 Average hourly MWh HHI and market concentration in the economic program: January 2022 through February 2023[64]

	Average Hourly MWh HHI			Top Four CSPs Share of Reduction			Top Four CSPs Share of Credit		
Month	2022	2023	Percent Change	2022	2023	Change in Percent	2022	2023	Change in Percent
Jan	7182	9953	38.6%	99.8%			99.8%		
Feb	7474	8965	20.0%	98.8%			99.0%		
Mar	8927			97.6%			97.8%		
Apr	7310			89.8%			88.3%		
May	7003			96.5%			96.8%		
Jun	7147			93.5%			93.1%		
Jul	7500			94.9%			94.1%		
Aug	6716			92.6%			87.2%		
Sep	8042			99.5%			99.8%		
Oct	9400			100.0%			100.0%		
Nov	8121			99.8%			99.8%		
Dec	7745			99.7%			99.8%		
Total	7826	9622	23.0%	94.8%	100.0%	5.2%	93.0%	100.0%	7.0%

63 All HHI calculations in this section are at the parent company level.
64 January and February 2023 reduction and credit share values are not reported based on confidentiality rules.

Market Performance

Table 6-20 shows the total MW reported reductions made by participants in the economic program and the total credits paid for these reported reductions in the years 2010 through 2023. The average credits per MWh paid decreased by $11.88 per MWh, 19.6 percent, from $60.62 per MWh in the first three months of 2022 to $48.74 per MWh in the first three months of 2023. The PJM real-time load-weighted average LMP in the first three months of 2023 was $30.28 per MWh, a decrease of $23.85 per MWh, 44.1 percent, compared to the average LMP in the first three months of 2022. Curtailed energy for the economic program was 6,411 MWh in the first three months of 2023, a decrease of 217.5 MWh, 3.3 percent, as compared to curtailed energy for the economic program in the first three months of 2022. Total credits paid for the economic load response program in the first three months of 2023 were $312,479, a decrease of $89,367, 22.2 percent, compared to the total credits paid for the economic load response program in the first three months of 2022.

Table 6-20 Credits paid to economic program participants: January through March, 2010 through 2023

(Jan-Mar)	Total MWh	Total Credits	$/MWh
2010	8,139	$321,648	$39.52
2011	3,272	$240,304	$73.45
2012	1,030	$30,406	$29.52
2013	21,048	$1,083,755	$51.49
2014	58,195	$12,727,388	$218.70
2015	38,644	$4,175,116	$108.04
2016	16,038	$672,506	$41.93
2017	12,973	$534,378	$41.19
2018	14,623	$951,955	$65.10
2019	7,260	$390,708	$53.82
2020	1,216	$34,124	$28.06
2021	3,912	$228,087	$58.31
2022	6,629	$401,846	$60.62
2023	6,411	$312,479	$48.74

Economic demand response resources that are dispatched by PJM in both the economic and emergency programs are paid the higher price defined in the emergency rules.[65] For example, assume a demand resource has an economic

65 "PJM. Manual 11: Energy & Ancillary Services Market Operations," § 10.4.5, Rev. 123 (Feb. 9, 2023).

offer price of $100 per MWh and an emergency strike price of $1,800 per MWh. If this resource were scheduled to reduce in the day-ahead energy market, the demand resource would receive $100 per MWh, but if an emergency event were called during the economic dispatch, the demand resource would receive its emergency strike price of $1,800 per MWh instead. The rationale for this rule is not clear.[66] All other resources that clear in the day-ahead market are financially firm at the clearing price. Payment at a guaranteed strike price and the ability to set energy market prices at the strike price effectively grant the seller the right to exercise market power.

Figure 6-2 shows monthly economic demand response credits and MWh, from January 1, 2010, through February 28, 2023.

Figure 6-2 Economic program credits and MWh by month: 2010 through February 2023

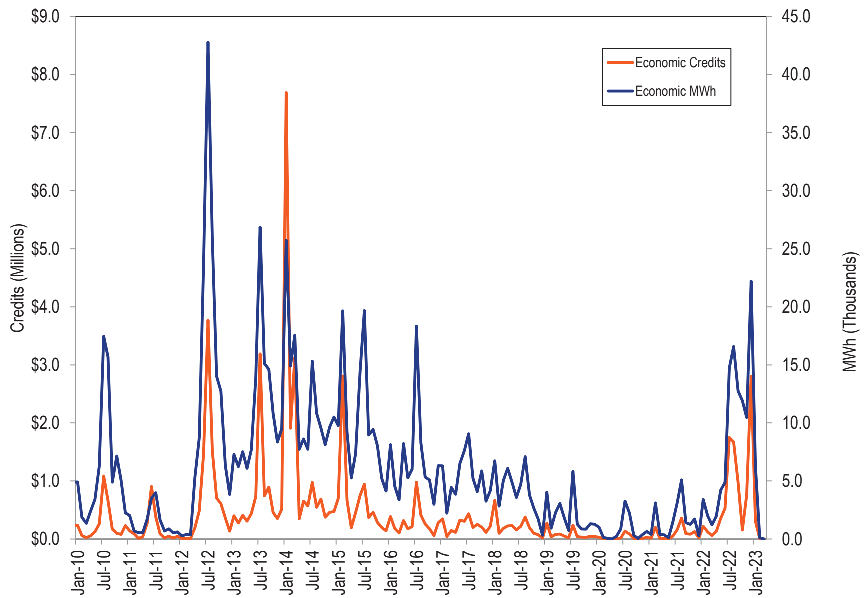


Table 6-21 shows performance for the first three months of 2022 and 2023 in the economic program by control zone. Total reported reductions under the economic program decreased by 218 MWh, 3.3 percent, from 6,629 MWh in the first three months of 2022 to 6,411 MWh in the first three months of 2023. Total revenue under the economic program decreased by $0.1 million, 22.2 percent, from $0.4 million in the first three months of 2022 to $0.3 million in the first three months of 2023.[67]

Emergency and economic demand response energy payments are uplift and not compensated by LMP revenues. Economic demand response energy costs are assigned to real-time exports from the PJM Region and real-time loads in each zone for which the load-weighted average real-time LMP for the hour during which the reduction occurred is greater than the price determined under the net benefits test for that month.[68] The zonal allocation is shown in Table 6-21.

66 *Offer Caps in Markets Operated by Regional Transmission Organizations and Independent System Operators*, Order No. 831, 157 FERC ¶ 61,115 (2016) ("Order No. 831").

67 Economic demand response reductions that are submitted to PJM for payment but have not received payment are not included in Table 6-21. Payments for Economic demand response reductions are settled monthly.

68 "PJM Manual 28: Operating Agreement Accounting," § 11.2.2, Rev. 90 (Jan. 25, 2023).

Table 6-21 Economic program participation by zone: January through March, 2022 and 2023

		Credits			MWh Reductions			Credits per MWh Reduction		
Zones	Zones	2022 (Jan-Mar)	2023 (Jan-Mar)	Percent Change	2022 (Jan-Mar)	2023 (Jan-Mar)	Percent Change	2022 (Jan-Mar)	2023 (Jan-Mar)	Percent Change
AECO	ACEC	$0.00	$0.00	NA	0	0	NA	NA	NA	NA
AEP	AEP	$125,975.71	$843.64	(99.3%)	1,822	19	(98.9%)	$69.12	$44.02	(36.3%)
APS	APS	$0.00	$0.00	NA	0	0	NA	NA	NA	NA
ATSI	ATSI	$88,577.18	$0.00	NA	1,745	0	NA	$50.77	NA	NA
BGE	BGE	$0.00	$0.00	NA	0	0	NA	NA	NA	NA
COMED	COMED	$19,993.17	$986.56	(95.1%)	494	49	(90.0%)	$40.46	$19.96	(50.7%)
DAY	DAY	$0.00	$0.00	NA	0	0	NA	NA	NA	NA
DUKE	DUKE	$0.00	$0.00	NA	0	0	NA	NA	NA	NA
DUQ	DUQ	$382.79	$303,987.80	79,313.7%	8	6,268	77,506.0%	$47.40	$48.50	2.3%
DOM	DOM	$0.00	$0.00	NA	0	0	NA	NA	NA	NA
DPL	DPL	$0.00	$0.00	NA	0	0	NA	NA	NA	NA
JCPL	JCPLC	$0.00	$0.00	NA	0	0	NA	NA	NA	NA
METED	MEC	$19,750.70	$3,600.72	(81.8%)	327	44	(86.6%)	$60.38	$82.02	35.8%
OVEC	OVEC	$0.00	$0.00	NA	0	0	NA	NA	NA	NA
PECO	PECO	$91,107.40	$1,425.31	(98.4%)	1,321	19	(98.6%)	$68.96	$75.84	10.0%
PENELEC	PE	$0.00	$0.00	NA	0	0	NA	NA	NA	NA
PEPCO	PEPCO	$0.00	$0.00	NA	0	0	NA	NA	NA	NA
PPL	PPL	$0.00	$0.00	NA	0	0	NA	NA	NA	NA
PSEG	PSEG	$56,059.19	$1,634.76	(97.1%)	911	13	(98.6%)	$61.53	$129.88	111.1%
REC	REC	$0.00	$0.00	NA	0	0	NA	NA	NA	NA
Total	Total	$401,846.14	$312,478.79	(22.2%)	6,629	6,411	(3.3%)	$60.62	$48.74	(19.6%)

Table 6-22 shows average reported MWh reductions and credits by hour for the first three months of 2022 and 2023. The average LMP during Load Response is the reduction weighted average hourly DA or RT load weighted LMP during the economic load response hour. In the first three months of 2022, 69.1 percent of the reported reductions and 68.7 percent of credits occurred in hours ending 0900 EPT to 2100 EPT, and in the first three months of 2023, 66.3 percent of the reported reductions and 65.8 percent of credits occurred in hours ending 0900 EPT to 2100 EPT. The average LMP during load response decreased by $16.53 per MWh, 22 percent, from $70.24 per MWh in the first three months of 2022 to $53.71 per MWh during 2022.

Table 6-22 Hourly frequency distribution of economic program reported MWh reductions and credits: January through March, 2022 and 2023

	MWh Reductions			Program Credits			Average LMP during Load Response		
Hour Ending (EPT)	2022 (Jan-Mar)	2023 (Jan-Mar)	Percent Change	2022 (Jan-Mar)	2023 (Jan-Mar)	Percent Change	2022 (Jan-Mar)	2023 (Jan-Mar)	Percent Change
1 through 6	547	424	(22%)	$31,258	$20,160	(36%)	$67.87	$46.40	(32%)
7	378	580	54%	$23,031	$28,552	24%	$84.39	$51.57	(39%)
8	483	803	66%	$30,655	$43,726	43%	$89.85	$57.05	(37%)
9	494	566	14%	$30,267	$28,678	(5%)	$71.55	$49.16	(31%)
10	419	397	(5%)	$24,154	$18,259	(24%)	$64.25	$45.52	(29%)
11	414	311	(25%)	$26,468	$14,839	(44%)	$69.57	$47.43	(32%)
12	334	224	(33%)	$18,980	$10,013	(47%)	$63.60	$44.48	(30%)
13	285	49	(83%)	$15,021	$2,099	(86%)	$62.43	$42.78	(31%)
14	270	5	(98%)	$15,488	$381	(98%)	$58.96	$72.78	23%
15	225	5	(98%)	$12,614	$565	(96%)	$56.41	$69.07	22%
16	204	5	(98%)	$11,107	$394	(96%)	$58.78	$69.26	18%
17	266	177	(33%)	$14,460	$7,788	(46%)	$67.31	$44.66	(34%)
18	439	783	78%	$26,298	$40,848	55%	$84.18	$53.56	(36%)
19	464	718	55%	$31,117	$35,216	13%	$77.56	$47.78	(38%)
20	433	571	32%	$28,506	$26,817	(6%)	$73.95	$47.15	(36%)
21	334	440	32%	$21,436	$19,866	(7%)	$72.33	$45.50	(37%)
22	283	178	(37%)	$18,007	$8,230	(54%)	$71.55	$46.08	(36%)
23 through 24	357	175	(51%)	$22,979	$6,048	(74%)	$69.81	$86.61	24%
Total	6,629	6,411	(3%)	$401,846	$312,479	(22%)	$70.24	$53.71	(22%)

Table 6-23 shows the distribution of economic program reported MWh reductions and credits by ranges of real-time zonal load-weighted average LMP in the first three months of 2023 and 2022. In the first three months of 2023, 0.7 percent of reported MWh reductions and 1.4 percent of program credits occurred during hours when the applicable zonal LMP was higher than $175 per MWh.

Table 6-23 Frequency distribution of economic program zonal load-weighted average LMP (By hours): January through March, 2022 and 2023

	MWh Reductions			Program Credits		
LMP	2022 (Jan-Mar)	2023 (Jan-Mar)	Percent Change	2022 (Jan-Mar)	2023 (Jan-Mar)	Percent Change
$0 to $25	29	12	(58%)	$1,323	$221	(83%)
$25 to $50	2,378	4,223	78%	$118,979	$197,065	66%
$50 to $75	2,594	1,769	(32%)	$182,595	$90,041	(51%)
$75 to $100	788	273	(65%)	$57,256	$15,355	(73%)
$100 to $125	276	45	(84%)	$16,287	$2,331	(86%)
$125 to $150	119	45	(62%)	$6,966	$2,983	(57%)
$150 to $175	109	0	(100%)	$5,273	$0	(100%)
> $175	336	44	(87%)	$13,169	$4,483	(66%)
Total	6,629	6,411	(3%)	$401,846	$312,479	(22%)

Economic Load Response revenues are paid by real-time loads and real-time scheduled exports as an uplift charge. Table 6-24 shows the sum of real-time and day-ahead Economic Load Response charges paid in each zone and paid by exports. In the first two months of 2023, real-time scheduled exports have paid the highest Economic Load Response charges.

Table 6-24 Zonal Economic Load Response charge: January through February, 2023[69]

Zone	January	February	Total
AECO	$1,954	$100	$2,054
AEP	$34,662	$863	$35,526
APS	$18,119	$551	$18,670
ATSI	$15,268	$396	$15,663
BGE	$16,116	$413	$16,530
COMED	$13,709	$152	$13,860
DAY	$5,342	$138	$5,480
DUKE	$6,847	$141	$6,988
DUQ	$3,157	$115	$3,271
DOM	$41,259	$1,336	$42,595
DPL	$4,429	$246	$4,676
EKPC	$4,062	$88	$4,150
JCPLC	$3,814	$246	$4,061
MEC	$6,248	$203	$6,450
OVEC	$36	$1	$37
PECO	$6,195	$471	$6,666
PE	$4,356	$151	$4,507
PEPCO	$11,201	$300	$11,501
PPL	$8,671	$437	$9,108
PSEG	$7,069	$473	$7,542
REC	$236	$18	$254
Exports	$92,222	$668	$92,890
Total	$304,972	$7,506	$312,479

Table 6-25 shows the total zonal Economic Load Response charge per GWh of real-time load and exports in the first two months of 2023.

Table 6-25 Zonal economic load response charge per GWh of load and exports: January through February, 2023

Zone	January	February	Zonal Average
ACEC	$0.003	$0.000	$0.001
AEP	$0.003	$0.000	$0.002
APS	$0.004	$0.000	$0.002
ATSI	$0.003	$0.000	$0.001
BGE	$0.006	$0.000	$0.003
COMED	$0.002	$0.000	$0.001
DAY	$0.004	$0.000	$0.002
DUKE	$0.003	$0.000	$0.002
DUQ	$0.003	$0.000	$0.001
DOM	$0.004	$0.000	$0.002
DPL	$0.003	$0.000	$0.002
EKPC	$0.003	$0.000	$0.002
JCPLC	$0.002	$0.000	$0.001
MEC	$0.000	$0.000	$0.000
OVEC	$0.003	$0.000	$0.002
PECO	$0.002	$0.000	$0.001
PE	$0.003	$0.000	$0.002
PEPCO	$0.005	$0.000	$0.002
PPL	$0.002	$0.000	$0.001
PSEG	$0.002	$0.000	$0.001
REC	$0.002	$0.000	$0.001
Exports	$0.021	$0.000	$0.011
Monthly Average	$0.004	$0.000	$0.002

Table 6-26 shows the monthly day-ahead and real-time Economic Load Response charges for 2022 and 2023. The day-ahead Economic Load Response charges increased by $44.1 thousand, 16.5 percent, from $267.3 thousand in the first two months of 2022 to $311.5 thousand in the first two months of 2023. The real-time Economic Load Response charges decreased $74.6 thousand, 98.7 percent, from $75.6 thousand in the first two months of 2022 to $1.0 thousand in the first two months of 2023.[70]

69 Load response charges were downloaded as of April 6, 2023 and may change as a result of continued PJM billing updates.

70 Load response charges were downloaded as of April 6, 2023, and may change as a result of continued PJM billing updates. Economic demand response reductions that are submitted to PJM for payment but have not received payment are not included. Payments for Economic demand response reductions are settled monthly.

Table 6-26 Monthly day-ahead and real-time economic load response charge: January 2022 through February 2023

	Day-ahead Economic Load Response Charge			Real-time Economic Load Response Charge		
Month	2022	2023	Percent Change	2022	2023	Percent Change
Jan	$208,026	$304,465	46.4%	$11,554	$507	(95.6%)
Feb	$59,319	$7,012	(88.2%)	$64,082	$495	(99.2%)
Mar	$17,440			$41,425		
Apr	$100,975			$30,536		
May	$264,451			$92,237		
Jun	$247,738			$278,463		
Jul	$1,574,857			$174,780		
Aug	$1,520,387			$151,364		
Sep	$772,279			$204,355		
Oct	$150,988			$4,205		
Nov	$757,878			$2,763		
Dec	$2,797,626			$9,227		
Total	$8,471,966	$311,477	(96.3%)	$1,064,991	$1,002	(99.9%)

Table 6-27 shows registered sites and MW for the last day of each month for the period January 1, 2019, through March 31, 2023. Registration is a prerequisite for CSPs to participate in the economic program. Average monthly registrations increased by 38, 11.7 percent, from 325 in the first three months of 2022 to 363 in the first three months of 2023. Average monthly registered MW increased by 452 MW, 19.8 percent, from 2,289 MW in the first three months of 2022 to 2,741 MW in the first three months of 2023.

Most economic demand response resources are registered in the emergency demand response program. Resources registered in both programs do not need to register for the same amount of MW. There are 106 economic registrations and 106 capacity registrations in the emergency program that share the same location IDs in both programs. There are 1,442.2 nominated economic MW and 1,160.7 nominated capacity MW in the emergency program that share the same location IDs in both programs.

Table 6-27 Economic program registrations on the last day of the month: 2019 through March 2023[71]

	2019		2020		2021		2022		2023	
Month	Registrations	Registered MW	Registrations	Registered MW	Registrations	Registered MW	Registrations	Registered MW	Registrations	Registered MW
Jan	374	2,651	377	2,909	277	1,495	323	2,233	353	2,722
Feb	370	2,640	382	2,912	275	1,503	323	2,256	362	2,710
Mar	378	2,648	380	2,941	284	1,514	330	2,377	375	2,790
Apr	366	2,594	350	2,917	293	1,538	330	2,382		
May	372	3,193	308	2,824	319	1,658	326	2,377		
Jun	370	2,768	285	1,418	313	2,136	315	2,323		
Jul	376	2,899	283	1,453	312	2,105	310	2,412		
Aug	360	2,885	292	1,482	322	2,122	318	2,451		
Sep	368	2,954	297	1,566	322	2,256	329	2,565		
Oct	375	2,909	275	1,361	332	2,267	333	2,575		
Nov	379	3,051	280	1,375	333	2,270	338	2,593		
Dec	383	3,070	282	1,327	320	2,256	359	2,640		
Avg	373	2,855	316	2,040	309	1,927	328	2,432	363	2,741

71 Data for years 2010 through 2017 are available in the *2017 State of the Market Report for PJM.*

The registered MW in the economic load response program are not a good measure of the MW available for dispatch in the energy market. Economic resources can dispatch up to the amount of MW registered in the program, but are not required to offer any MW. Table 6-28 shows the sum of maximum economic MW dispatched by registration each month from January 1, 2011, through February 28, 2023. The monthly maximum is the sum of each registration's monthly noncoincident maximum dispatched MW and annual maximum is the sum of each registration's annual noncoincident maximum dispatched MW. The monthly maximum dispatched MW increased in January and decreased in February of 2023 compared to the same months in 2022.[72]

Table 6-28 Sum of maximum MW reported reductions for all registrations per month: 2011 through February 2023

Sum of Peak MW Reductions for all Registrations per Month													
Month	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Jan	132	110	193	446	169	139	123	142	88	28	21	34	50
Feb	89	101	119	307	336	128	83	70	58	11	86	34	16
Mar	81	72	127	369	198	120	111	71	38	12	20	30	
Apr	80	108	133	146	143	118	54	71	41	3	22	43	
May	98	143	192	151	161	131	169	70	22	12	9	53	
Jun	561	954	433	483	833	121	240	105	26	38	125	110	
Jul	561	1,631	1,088	665	1,362	1,316	936	518	770	135	134	151	
Aug	161	952	497	358	272	249	141	581	33	99	827	163	
Sep	84	451	530	795	816	263	140	112	76	31	35	88	
Oct	81	242	168	214	136	150	88	69	29	9	31	67	
Nov	86	165	155	166	127	116	81	54	35	12	31	58	
Dec	88	98	168	155	122	147	83	11	31	14	19	116	
Annual	840	1,942	1,486	1,739	1,858	1,451	1,217	758	830	196	921	264	63

Table 6-29 shows total settlements submitted for 2011 through 2023. A settlement is counted for every day on which a registration is dispatched in the economic program.

Table 6-29 Settlements submitted in the economic program: January through March, 2011 through 2023

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Number of Settlements	91	21	368	1,314	602	267	347	361	172	83	123	369	100

Table 6-30 shows the number of CSPs, and the number of participants in their portfolios, submitting settlements for the 2011 through 2023. The number of active participants decreased by 5, 33.3 percent, from 15 in the first three months of 2022 to 10 in the first three months of 2023. All participants must be registered through a CSP.

Table 6-30 Participants and CSPs submitting settlements in the economic program by year: January through March, 2011 through 2023

(Jan-Mar)	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Active CSPs	5	4	9	12	11	6	6	11	9	7	8	5	5
Active Participants	25	9	49	115	47	17	19	26	18	9	18	15	10

Issues

FERC Order No. 831 requires that each RTO/ISO market monitoring unit verify all energy offers above $1,000 per MWh.[73] Economic resources offer into the energy market and must provide supporting documentation to offer above $1,000 per MWh. FERC stated, "[t]he offer cap reforms, however, do not apply to capacity-only demand response resources that do not submit incremental energy offers into energy markets."[74] Demand resources participate in both the capacity and energy markets and are not capacity only resources. It is not clear whether FERC intended to exclude demand resources with high strike prices from the requirements of FERC Order No. 831. Demand resources should not be permitted to make offers above $1,000 per MWh without the same verification requirements applied to economic resources or generation resources. The MMU recommends that the rules for maximum offer for the emergency and pre-emergency program match the maximum offer for generation resources.

On April 1, 2012, FERC Order No. 745 was implemented in the PJM economic program, requiring payment of full LMP for dispatched demand resources when a net benefits test (NBT) price threshold is exceeded. This approach replaced the payment of LMP minus the charges for wholesale power and transmission included in customers' tariff rates. Following FERC Order No. 745, all ISO/RTOs are required to calculate an NBT threshold price

72 Maximum MW reductions were downloaded on April 6, 2023, and may change as a result of continued PJM billing updates.

73 157 FERC ¶ 61,115 at P 139 (2016).

74 *Id.* at 8.

each month above which the net benefits of DR are deemed to exceed the cost to load.

PJM calculates the NBT price threshold by first retrieving generation offers from the same month of the prior calendar year for which the calculation is being performed. PJM then adjusts a portion of each prior year offer, representing the typical share of fuel costs in energy offers in the PJM Region, for changes in fuel prices based on the ratio of the reference month spot fuel price to the study month forward fuel price. To accomplish this adjustment, the ratio of forward prices for the study month to the spot fuel prices for the reference month is used as a scaling factor. If the forward price for the study month was $7.08 and the spot fuel price from the reference month was $6.75, then the ratio is 1.05. The offers of generation units are then adjusted by this scaling factor. The price of fuel typically represents 80 to 90 percent of a generator's offer with the remainder being variable operations and maintenance costs. Where generators offer multiple points on a curve, each point on the curve is adjusted in this manner. The offers are then combined to create daily supply curves for each day in the period. The daily curves are then averaged to form an average supply curve for the study month. PJM then uses a non-linear least squares estimation technique to determine an equation that approximates and smooths this average supply curve. The NBT threshold price is the price at the point where the price elasticity of supply is equal to 1.0 for this estimated supply curve equation.[75] PJM publishes the details of the equation and parameters each month along with the NBT results.

The NBT test is a crude tool that is not based in market logic. The NBT threshold price is a monthly estimate calculated from a monthly supply curve that does not incorporate real-time or day-ahead prices. In addition, it is a single threshold price used to trigger payments to economic demand response resources throughout the entire RTO, regardless of their location and regardless of locational prices.

The necessity for the NBT test is an illustration of the illogical approach to demand side compensation embodied in paying full LMP to demand resources. The benefit of demand side resources is not that they suppress market prices, but that customers can choose not to consume at the current price of power, that individual customers benefit from their choices and that the choices of all customers are reflected in market prices. If customers face the market price, customers should have the ability to not purchase power and the market impact of that choice does not require a test for appropriateness.

When the zonal LMP is above the NBT threshold price, economic demand response resources that reduce their power consumption are paid the full zonal LMP. When the zonal LMP is below the NBT threshold price, economic demand response resources are not paid for any load reductions.[76]

Table 6-31 shows the NBT threshold price for the historical test from August 2010 through July 2011, and April 2012, when FERC Order No. 745 was implemented in PJM, through March 2023. The historical test was used as justification for the method of calculating the NBT for future months. From 2012 through 2021, the NBT threshold price exceeded the lowest historical test result of $34.07 per MWh one time, in March 2014 when the NBT threshold price was $34.93. The NBT threshold price exceeded the lowest historical test result of $34.07 per MWh in 10 of 12 months of 2022. In the first three months of 2023, the NBT threshold price exceeded the lowest historical test result of $34.07 per MWh in a single month, January.

75 "PJM Manual 11: Energy & Ancillary Services Market Operations," §10.3.1, Rev. 123 (Feb. 9, 2023).

76 "PJM Manual 11: Energy & Ancillary Services Market Operations," §10.3.4, Rev. 123 (Feb. 9, 2023).

Table 6-31 Net benefits test threshold prices: August 2010 through March 2023

	Historical Test ($/MWh)	Net Benefits Test Threshold Price ($/MWh)												
Month	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Jan		$40.27		$25.72	$29.51	$29.63	$23.67	$32.60	$26.27	$29.44	$20.04	$18.11	$26.93	$40.25
Feb		$40.49		$26.27	$30.44	$26.52	$26.71	$31.57	$24.65	$23.49	$19.29	$18.70	$34.59	$29.79
Mar		$38.48		$25.60	$34.93	$24.99	$22.10	$30.56	$25.50	$22.15	$17.44	$20.82	$30.00	$23.75
Apr		$36.76	$25.89	$26.96	$32.59	$24.92	$19.93	$30.45	$25.56	$22.36	$15.91	$23.47	$35.14	
May		$34.68	$23.46	$27.73	$32.08	$23.79	$20.69	$29.77	$25.52	$21.01	$14.69	$21.40	$42.94	
Jun		$35.09	$23.86	$28.44	$31.62	$23.80	$20.62	$27.14	$23.59	$20.20	$15.56	$22.35	$44.29	
Jul		$36.78	$22.99	$29.42	$31.62	$23.03	$20.73	$24.42	$23.57	$19.76	$14.66	$21.59	$48.67	
Aug	$35.57		$24.47	$28.58	$29.85	$23.17	$23.24	$22.75	$23.53	$19.57	$14.58	$20.52	$44.08	
Sep	$34.07		$24.93	$28.80	$29.83	$21.69	$24.70	$21.51	$22.23	$18.19	$15.16	$23.06	$55.39	
Oct	$38.10		$25.96	$29.13	$30.20	$21.48	$26.50	$21.70	$23.84	$20.20	$17.25	$24.24	$55.97	
Nov	$36.83		$25.63	$31.63	$29.17	$22.28	$29.27	$26.41	$23.89	$21.11	$18.35	$29.20	$49.57	
Dec	$37.04		$25.97	$28.82	$29.01	$22.31	$29.71	$29.16	$26.35	$22.24	$19.47	$32.85	$42.75	
Average	$36.32	$37.51	$24.80	$28.09	$30.91	$23.97	$23.99	$27.34	$24.54	$21.64	$16.87	$23.03	$42.53	$31.26

Table 6-32 shows the number of hours that at least one zone in PJM had day-ahead LMP or real-time LMP higher than the NBT threshold price.[77] In the first three months of 2023, the highest zonal LMP in PJM was higher than the NBT threshold price 1,526 hours out of 2,159 hours, or 70.7 percent of all hours. Reductions occurred in 250 hours, 16.4 percent, of those 1,526 hours in the first two months of 2023. The last three columns illustrate how often economic demand response activity occurred when LMPs exceeded NBT threshold prices for January 1, 2022, through February 28, 2023. There are no economic payments when demand response occurs and zonal LMP is below the NBT threshold. Demand response reported reductions occurred in none of the hours in which LMP was below the NBT threshold price in 2022, and none of the hours in which LMP was below the NBT threshold price in the first two months of 2023.

Table 6-32 Hours with price higher than NBT and economic load response occurrences in those hours: 2021 through March 2023

	Number of Hours		Number of Hours with LMP Higher than NBT			Percent of NBT Hours with Economic Load Response		
Month	2022	2023	2022	2023	Percent Change	2022	2023	Percentage Change
Jan	744	744	724	458	(36.7%)	70.3%	36.9%	(33.4%)
Feb	672	672	663	412	(37.9%)	47.8%	19.7%	(28.2%)
Mar	743	743	742	656	(11.6%)	55.3%		
Apr	720		720			66.4%		
May	744		744			82.9%		
Jun	720		684			71.1%		
Jul	744		680			71.3%		
Aug	744		744			68.5%		
Sep	720		623			68.7%		
Oct	744		529			57.5%		
Nov	721		569			48.9%		
Dec	744		702			69.8%		
Total	8,760	2,159	8,124	1,526	(81.2%)	65.4%	16.4%	(49.0%)

77 The MWh for demand resources were downloaded as of April 6, 2023, and may change as a result of continued PJM billing updates.

Energy Efficiency

Calculating the Nominated MW value for Energy Efficiency (EE) resources is different than calculating the Nominated MW value for other capacity resources. The maximum amount of Nominated MW a generator can offer into the capacity market is based on the maximum output of a generator. EE resources do not produce power, but are intended to reduce power consumption. The Nominated MW for EE resources are not measured, although they could be, but a calculated value based on a set of largely unverified and unverifiable assumptions. An installed EE resource may participate as a capacity resource for up to four consecutive delivery years.[78]

Prescriptive energy efficiency MW have an assumed savings calculated based on an assumed installation rate and the difference between the assumed electricity usage of what is being replaced and the assumed electricity usage of the new product. All lighting EE is prescriptive. The majority of EE MW offered into the PJM Capacity Market is prescriptive energy efficiency MW. The measurement and verification method for prescriptive energy efficiency projects relies on neither measurement nor verification but instead relies on unverified assumptions and is too imprecise to rely on as a source of capacity comparable to capacity from a power plant. The nonprescriptive measurement and verification methods are also inadequate and rely on samples and assumptions for limited periods.[79] There is no evidence that the programs result in changed behavior or increases in savings.

The MMU recommends that Energy Efficiency Resources (EE) not continue to be included in the capacity market because PJM's load forecasts now account for EE, unlike the situation when EE was first added to the capacity market.[80] EE should not be part of the capacity market. EE is appropriately and automatically compensated through the markets because to the extent that it reduces energy and capacity use, it reduces customer payments for energy and capacity. EE is appropriately incorporated in PJM forecasts, so the original logic for the inclusion of EE in the capacity market is no longer correct. While EE does not affect the clearing price when the EE addback is done correctly, customers do pay for the cleared quantity of EE at market clearing prices. These direct payments to EE in the capacity market are an overpayment by customers.

The MMU recommends that, if energy efficiency resources remain in the capacity market, PJM codify eligibility requirements to claim the capacity rights to energy efficiency installations in the tariff and that PJM institute a registration system to track claims to capacity rights to energy efficiency installations and document installation periods of energy efficiency installations. The purpose of the registration system is to prevent duplicative claims to capacity rights and to document installation periods of energy efficiency to verify eligibility for continued participation measures. Energy Efficiency projects should be clearly identified by retail customer account, year of project installation and a description of the Energy Efficiency project. Energy Efficiency Resources are eligible to participate as supply in RPM for up to four years following their installation. Beyond the fourth year, the energy savings benefit of an Energy Efficiency project is incorporated into the load forecast used for RPM Auctions.

A registration system would also serve the benefit of preventing multiple Energy Efficiency Providers from claiming capacity rights to the same project. The Energy Efficiency Resource Provider offering an Energy Efficiency Resource as a Capacity Resource into RPM must demonstrate to PJM that it has the legal authority to claim the demand associated with such Energy Efficiency Resource.[81] The Energy Efficiency Resource Provider can satisfy this requirement by submitting to PJM a written sworn, notarized statement of one of its corporate officers certifying that the Energy Efficiency Resource Provider has the legal authority to claim the demand reduction associated with the EE installations that constitute the Energy Efficiency Resource for the applicable delivery year. The Energy Efficiency Resource Provider can also satisfy this requirement by including a statement in their Energy Efficiency Post-Installation Measurement & Verification Report that they have legal authority to claim the demand reduction associated with the EE installations that constitute the Energy Efficiency Resource for the applicable delivery

78 PJM. "Manual 18: PJM Capacity Market," § 4.4, Rev. 55 (Feb. 9, 2023).
79 PJM. "Manual 18B: Energy Efficiency Measurement & Verification," § 2.2 Rev. 05 (Sep. 21, 2022).
80 "PJM Manual 19: Load Forecasting and Analysis," § 3.2 Development of the Forecast, Rev. 35 (Dec. 31, 2021).
81 EE Post-Installation Measurement & Verification Report Template, <https://www.pjm.com/-/media/markets-ops/rpm/rpm-auction-info/ee-post-installation-mv-report-template.ashx> *(Accessed Aug. 5, 2022).*

year. The MMU recommends that, if Energy Efficiency resources remain in the capacity market, PJM codify eligibility requirements to claim the capacity rights to Energy Efficiency installations in the Tariff. These eligibility requirements should specifically define the conditions under which an Energy Efficiency Resource Provider may claim the capacity rights to Energy Efficiency installations as well as evidentiary requirements such as signed contracts with their customers conferring such rights. Energy efficiency resources are included in the PJM Capacity Market.

Table 6-33 shows the amount of energy efficiency (EE) resources in PJM on June 1 for the 2011/2012 through 2022/2023 Delivery Years. EE resources may participate in PJM without restrictions imposed by a state unless the Commission authorizes a state to impose restrictions.[82] Only Kentucky has been authorized by the Commission.[83] The total MW of energy efficiency resources committed increased by 19.3 percent from 4,806.2 MW in the 2021/2022 Delivery Year to 5,734.8 MW in the 2022/2023 Delivery Year.[84]

Table 6-33 Energy efficiency resources (MW): 2011/2012 through 2022/2023 Delivery Years

Delivery Year	EE RPM Cleared (UCAP MW)	Total RPM Cleared (UCAP MW)	EE Percent Cleared
2011/2012	76.4	134,139.6	0.1%
2012/2013	666.1	141,061.8	0.5%
2013/2014	904.2	159,830.5	0.6%
2014/2015	1,077.7	161,092.4	0.7%
2015/2016	1,189.6	173,487.4	0.7%
2016/2017	1,723.2	179,749.0	1.0%
2017/2018	1,922.3	180,590.3	1.1%
2018/2019	2,296.3	175,957.4	1.3%
2019/2020	2,528.5	177,040.6	1.4%
2020/2021	3,569.5	173,688.5	2.1%
2021/2022	4,806.2	174,713.0	2.8%
2022/2023	5,734.8	150,465.2	3.8%

82 *See* 161 FERC ¶ 61,245 at P 57 (2017); 107 FERC ¶ 61,272 at P 8 (2008).
83 FERC made an exception for Kentucky when it determined that RERRAs must obtain FERC approval prior to excluding EE. FERC explained that "the Commission accepted such condition at the time the Kentucky Commission approved the integration of Kentucky Power into PJM." 161 FERC ¶ 61,245 at P 66 (2017).
84 See the *2021 State of the Market Report for PJM*, Vol. 2, Section 5: Capacity Market, Table 5-13.

Distributed Energy Resources

Distributed Energy Resources (DER) generally include small scale generation directly connected to the grid, generation connected to distribution level facilities, behind the meter generation and some energy storage facilities. FERC issued Order No. 2222 on September 17, 2020, with the goal of removing barriers for small distributed resources to enter the wholesale market by allowing them to aggregate in order to encourage competition.[85]

PJM made a compliance filing at FERC on February 1, 2022, and the MMU provided comments.[86] [87] FERC issued an order on March 1, 2023.[88] PJM submitted an informational filing and a 30-day compliance filing on March 31, 2023.[89]

In the March 1st Order, FERC directed PJM to file, within 30 days of the date of the issuance of the order, a further compliance filing to remove its proposal to exempt DER Capacity Aggregation Resources that include component DERs that are co-located with retail end-use load from the capacity market power mitigation rules.[90] FERC rejected the proposed rule because it requires reforms to existing capacity market power mitigation rules, which are outside the scope of the proceeding. The other directives, which are required to be filed by September 1, 2023,[91] include clarifying rules around the resources that both curtail load and inject energy, removing automatic approval for net energy metering resources' participation in the ancillary services market, clarifying the definition of double counting, reconsidering single node aggregation in the energy market, removing pre-registration process and specifying utility review criteria.

PJM's March 31st Filing was not responsive to FERC's directive. PJM proposed to exempt a DER Capacity Aggregation Resource or a part of a DER Capacity

85 172 FERC ¶ 61,247 at PP 6-7 (2020).
86 Order No. 2222 Compliance Filing of PJM Interconnection, L.L.C., Docket No. ER22-962 (February 1, 2022).
87 Comments of the Independent Market Monitor for PJM, Docket No. ER22-962 (April 1, 2022); Answer and Motion for Leave to Answer of the Independent Market Monitor for PJM, Docket No. ER22-962 (April 18, 2022); Answer and Motion for Leave to Answer of the Independent Market Monitor for PJM, Docket No. ER22-962 (May 19, 2022); Comments of the Independent Market Monitor for PJM, Docket No. ER22-962 (July 28, 2022).
88 182 FERC ¶ 61,143 (2023).
89 PJM Interconnection, L.L.C., Order No. 2222 Informational Update Regarding Effective Date Implementation, Docket No. ER22-962-001 (March 31, 2023); PJM Interconnection, L.L.C., Order No. 2222 30-Day Compliance Filing Docket No. ER22-962-002 (March 31, 2023).
90 Individual DERs in DER Aggregation Resources. See definitions in the February 1st Filing.
91 Notice of Extension of Time, Docket No. ER22-962-001 (April 11, 2023).

Aggregation Resource that consists solely of Component DER co-located with retail end-use load, from the capacity market power mitigation rules (MSOC and MOPR).

Getting the rules correct at the beginning of DER development is essential to the active and effective participation of DER in the wholesale power markets in a manner that enhances rather than undercuts the efficiency and competitiveness of the power markets.

The EDCs' dual role as the distribution system operator and as a DER aggregator is a threat to PJM's competitive market. When an EDC, acting in its proposed role as a market participant, controls its competitors' access to the market, the result is structurally not competitive. The result would be to create barriers to competition, exactly the opposite of FERC's intent. The March 1st Order refused to prevent EDCs from serving as DER aggregators because Order 2222 requires RTOs/ISOs not limit the business models under which DER aggregators can operate. The March 1st Order, however, stated a possibility of revisiting the issue if FERC discovers "evidence of undue discrimination regarding the participation of DER aggregations in RTO/ISO markets."[92] The exercise of market power should be prevented, not fixed after the fact. The MMU continues to recommend that EDCs not be allowed to participate in markets as DER aggregators in addition to their EDC role.

The PJM market is a nodal market because nodal markets provide efficient price signals to resources in an economically dispatched, security constrained market. Allowing DER aggregation across nodes is not necessary and would distort market signals indicating where capacity and energy are needed. The March 1st Order asked PJM to explore an option to allow broader aggregation where technically feasible by identifying areas with historically minimal congestion. It is, however, impossible to know when constraints will bind ahead of time. Constraints are dynamic and often simultaneous. Even if one could identify a group of pricing nodes that do not have an impact on a particular constraint, it is very likely that they have an impact on another constraint. Even if that group of pricing nodes does not have impact on any constraint at one point in time, it is very likely that they have impact on a constraint (or multiple constraints) at another time. Aggregation behind a single node is feasible, will not threaten the nodal market principle, and will encourage competition. The MMU recommends that PJM use a nodal approach for DER participation in PJM markets.

Under the proposed DER rules, favorable treatment of resources that participate in the DER aggregation model over other resources includes: exemption from the PJM interconnection process; no must offer requirement in the capacity market; exemption from the RPM Minimum Offer Price Rule ("MOPR") when co-located with retail load; exemption from the market seller offer cap ("MSOC") when co-located with retail load; and ability to reduce load and inject power into the grid at the same time. These exemptions from basic market rules are not appropriate even for small participants and are not necessary to facilitate participation. But large DERs that are already capable of participating in the PJM markets under the current rules should not be given the option to exploit the new rules. The March 1st Order accepted PJM's proposed maximum size requirement of 5 MW for component DERs but did not require PJM to propose a maximum size requirement for DER Aggregation Resources. This loophole would allow larger DERs to divide one larger resource into multiple DERs less than 5 MW and register them as one DER Aggregation Resource. To avoid this loophole, there should be a maximum size requirement on the DER Aggregation Resource. The MMU recommends that PJM include a 5.0 MW maximum size cap on DER aggregations.

DERs should not be exempt from market power mitigation. Small resources can and do have market power. There is no downside to having market power mitigation rules. If they are not triggered, then there is no issue. But there is a downside to not having market power mitigation rules. The March 1st Order accepted PJM's proposal to require DER aggregation resources to submit cost-based offers but failed to address offer parameter mitigation. The March 31st Filing exempts component DERs co-located with retail load from the capacity MSOC and the MOPR. The absence of consistently applied market power mitigation rules across resource types creates the potential for the exercise of market power and noncompetitive market outcomes.

92 The March 1st Order at P334.

Demand response resources are not the same as DER aggregation resources. Demand response resources cannot inject energy into the grid while DER aggregation resources can; demand response resources are modeled as load reduction while DER aggregation resources should be modeled as generation. The rules for demand response resources and the rules for DER aggregation resources should not be the same because the two resource types function very differently in the PJM market.

No resource should be paid more than once for its services. In most of the states in PJM, net energy metering means paying for resources on the distribution system at the full retail rate. As a result of the fact that retail rates include all wholesale market costs, there is no way to avoid double compensation for net energy metering resources if they were to participate directly in any of the wholesale markets. The March 1st Order directed PJM to remove the automatic approval for net energy metering resources participation in the ancillary services market because certain state net metering tariffs currently include compensation for ancillary services.

Peak Shaving Adjustment

Peak Shaving Adjustment (PSA) provides an alternative means for demand response to participate in the Reliability Pricing Model (RPM). Rather than being on the supply side of the capacity market, a PSA participates on the demand side through a modified peak load forecast for the zone in which the Peak Shaving Adjustment resources are located. The peak shaving adjusted load forecast is included in the VRR curve. But the resultant reduction in capacity obligation is socialized across all loads in the zone rather than directly benefitting the resources providing the Peak Shaving Adjustment.[93] This eliminates the incentive for individual customers to participate in peak shaving. The solution is in a retail rate design that directly assigns the benefits of peak shaving to individual customers. The retail rate design is within the authority of state regulators and not in the wholesale markets. Not surprisingly, although PSA was first available for inclusion in the revised March 2016 PJM Load Forecast Report, PJM has not yet approved any PSA for use in a load forecast.

93 See "Peak Shaving Adjustment Proposal," Docket No. ER19-511-000 (December 7, 2018).

A PSA plan must include: the basis for the planned reductions; a THI trigger for interruption; the duration of the interruption in hours; the MW value of the curtailment; the months of the offer; all historical addbacks for the nominated programs.[94] Any resource selling a PSA must reduce load on any day in which its trigger is met or exceeded. The trigger is based on the actual maximum daily temperature humidity index (THI) for the relevant PJM zone. When the trigger is met, the PSA must comply with its defined offer parameters including number of hours of interruption. Failure to operate to these parameters will lead to a reduction in the peak shaving adjustment value in future delivery years. Performance is measured based on the aggregated Customer Baseline (CBL). PJM applies a three year rolling average of the annual peak shaving performance ratings to the program's total participating MW in order to determine its peak shaving adjustment.

Performance Assessment Events

There were two performance assessment events in the last 12 months in PJM. The first event was in the AEP Marion Subzone and involved only demand resources. The second was a result of Winter Storm Elliott.

Definition of Performance

The definition of performance does not require an actual load reduction in response to a notice from PJM. What is termed an actual load reduction is measured as the difference between the amount of capacity paid for (PLC) and the metered load. If a demand resource location was already at a reduced load level when PJM called a PAI, the demand resource would be deemed to have performed if the PLC less the metered load level was equal to the ICAP sold in the capacity market.

For a Firm Service Level customer on a registration, the actual load reduction provided for the hour ending that includes a Performance Assessment Interval in the summer period (June through October and May of the Delivery Year) is calculated as the end-use customer's Peak Load Contribution minus the hourly metered load multiplied by the loss factor.

94 "PJM Manual 19: Load Forecasting and Analysis," Attachment D, Rev. 35 (December 31, 2021).

For the non-summer period (November through April of the Delivery Year), the actual load reduction for a Performance Assessment Interval is calculated as the end-use customer's Winter Peak Load multiplied by the Zonal Winter Weather Adjustment Factor multiplied by the loss factor, minus the hourly metered load multiplied by the loss factor.

Performance Shortfalls

Nonperformance during a PAI is measured by comparing a resource's actual performance to their expected performance. The expected performance of a DR resource is its CP commitment in ICAP terms. The actual performance of a DR resource is defined as the demand response provided plus the resource's real-time reserve or regulation assignment, if any. Ancillary services are determined as the real-time regulation or reserves on the resource. The demand response, or load reduction, provided is defined as the PLC minus the metered load.

The expected and actual performance for DR resources are calculated as:[95]

Expected Performance = CP Capacity Commitment (ICAP)

Actual Performance = Load Reduction + Regulation/Reserve Assignment

If a resource's actual performance is less than the expected performance, the resource is assessed a nonperformance penalty.

Emergency Energy Credits

Emergency and pre-emergency demand response dispatched during a load management event by PJM are eligible to receive emergency energy payments if registered under the full program option.[96] The full program option includes an energy payment for load reductions during a pre-emergency or emergency event for demand response events and capacity payments. The strike price is set by the CSP before the delivery year starts and cannot be changed during the delivery year. The demand resource energy payments are equal to the higher of hourly zonal LMP or a strike price energy offer made by the participant, including a dollar per MWh minimum dispatch price and an associated shutdown cost. The energy provided by a demand resource eligible for emergency energy payments is equal to the CBL less the RT metered load.

95 PJM. "Manual 18: Capacity Market," § 8.4A, Rev. 55 (Feb. 9, 2023).
96 PJM. "Manual 11: Energy & Ancillary Services Market Operations," § 10.2.1, Rev. 123 (Feb. 9, 2023).

Settlements

Nonperformance assessments are billed starting three calendar months after the calendar month that included the performance assessment event and are spread across the remaining months in the delivery year.[97] Monthly charges and credits are billed by dividing the total dollar amount due or owed by the number of months remaining in the delivery year.

Metered demand response data are not telemetered to PJM but rely on EDC meter reading cycles. That is the primary reason that demand response data is provided with such a long lag. Demand response data are provided to PJM through the DR Hub System 45 days after the end of the month in which a Performance Assessment Interval occurred.

For example, load management compliance data for Elliott were provided to PJM by February 14, 2023. Load management emergency energy settlement data were provided to PJM by February 21, 2023, for the event on December 23, 2022. Load management emergency energy settlement data were provided to PJM by February 22, 2023, for the event on December 24, 2022.

PJM bills charges and credits for performance during Performance Assessment Intervals within three calendar months after the calendar month that included the Performance Assessment Intervals. Non-Performance Charges are amortized over the number of months remaining in the delivery year. If there are less than six months remaining in the current delivery year, PJM may, with prior notice to PJM Members, allocate in equal amounts any Non-Performance Charge in the remaining monthly bills for the current delivery year plus up to six monthly bills into the following delivery year (but in no event shall the total Non-Performance Charge be divided in more than nine monthly bills).

97 PJM. "Manual 18: Capacity Market," § 8.4A, Rev. 55(Feb. 9, 2023).

For the June 2022 performance assessment event, charges and credits were first billed starting in the September 2022 monthly bill, issued in October, and continue through the May 2023 monthly bill.

For any Non-Performance Charges associated with Performance Assessment Intervals from December 23, 2022 and December 24, 2022, a Capacity Market Seller may elect to divide the total amount of Non-Performance Charges by either the number of remaining monthly bills in the current Delivery Year, or the number of remaining monthly bills in the current Delivery Year plus six additional monthly bills into the following Delivery Year (nine bills). For an election under the second option, the monthly Non-Performance Charges are levelized, including interest for the six-month period following the current Delivery Year. The interest rate is electric interest rate established by the Federal Energy Regulatory Commission at the time of such election.[98]

Performance Assessment Event – AEP_Marion Subzone

On June 14, 15 and 16, 2022, PJM dispatched Pre-Emergency and Emergency DR resources in the Columbus, Ohio area of the AEP Zone defined as the AEP_MARION Load Management Subzone. These actions triggered Performance Assessment Intervals (PAIs) that require PJM to evaluate the performance of all resources located in the Emergency Action Area for each applicable five minute interval (PAI).[99]

On June 14, 2022, a Pre-Emergency and Emergency Load Management Reduction Action was issued at 1550 EPT and ended on June 14, 2022 at 2200 EPT. Quick Lead resources were required to fully implement their load reductions within 30 minutes, by 1620 EPT. Short Lead resources were required to fully implement their load reductions within 60 minutes, by 1650 EPT. Long Lead resources were required to fully implement their load reductions within 120 minutes, by 1750 EPT.

Table 6-34 Load management reduction action event times for June 14, 2022

Product Types	Lead Time	Notification Time (EPT)	Event Start (EPT)	Event End (EPT)
Emergency and Pre-Emergency	Quick (30 min)	1550	1620	2200
Emergency and Pre-Emergency	Short (60 min)	1550	1650	2200
Emergency and Pre-Emergency	Long (120 min)	1550	1750	2200

On June 15, 2022, a Pre-Emergency and Emergency Load Management Reduction Action was issued at 1050 EPT and ended on June 15, 2022 at 2200 EPT. Quick Lead resources were required to fully implement their load reductions within 30 minutes, by 1120 EPT. Short Lead resources were required to fully implement their load reductions within 60 minutes, by 1150 EPT. Long Lead resources were required to fully implement their load reductions within 120 minutes, by 1250 EPT.

Table 6-35 Load management reduction action event times for June 15, 2022

Product Types	Lead Time	Notification Time (EPT)	Event Start (EPT)	Event End (EPT)
Emergency and Pre-Emergency	Quick (30 min)	1050	1120	2200
Emergency and Pre-Emergency	Short (60 min)	1050	1150	2200
Emergency and Pre-Emergency	Long (120 min)	1050	1250	2200

On June 16, 2022, a Pre-Emergency and Emergency Load Management Reduction Action was issued at 1230 EPT and ended on June 16, 2022 at 1700 EPT. Quick Lead resources were required to fully implement their load reductions within 30 minutes, by 1300 EPT. Short Lead resources were required to fully implement their load reductions within 60 minutes, by 1330 EPT. Long Lead resources were required to fully implement their load reductions within 120 minutes, by 1430 EPT.

Table 6-36 Load management reduction action event times for June 16, 2022

Product Types	Lead Time	Notification Time (EPT)	Event Start (EPT)	Event End (EPT)
Emergency and Pre-Emergency	Quick (30 min)	1230	1300	1700
Emergency and Pre-Emergency	Short (60 min)	1230	1330	1700
Emergency and Pre-Emergency	Long (120 min)	1230	1430	1700

98 OATT, Attachment DD § 10A
99 OATT, Attachment DD § 10A

Performance

Any discussion of demand resource performance during a PAI must recognize the significant problems with the definition of performance for demand resources. As defined by PJM rules, performance, contrary to intuition, does not mean actually reducing load in response to a PJM request for demand resources. Performance means only that, on a net portfolio basis, the amount of capacity paid for in the capacity market (PLC) minus actual metered load is equal to the amount of demand side capacity sold in the capacity market (ICAP).

The standard reporting of demand side response is therefore misleading because it includes loads that were already lower for any reason as a response.

Immediately preceding the call for Load Management resources on June 14, 56 percent of registrations were already at load levels equal to or, below, their Peak Load Contribution. Immediately preceding the call for Load Management resources on June 15th, 62 percent of registrations were already at load levels equal to or, below, their Peak Load Contribution. Immediately preceding the call for Load Management resources on June 16th, 54 percent of registrations were already at load levels equal to or, below, their Peak Load Contribution.

Nonperformance Charges

Nonperformance charge rates applied during PAI are calculated on a modeled LDA basis for the relevant delivery year. The nonperformance charge rate for a specific resource is based on the Net CONE expressed in $/MW-day in ICAP for the LDA in which the resource is modeled and is calculated as:[100]

Nonperformance Charge Rate ($/MW-5-Minute Interval) = [(Net CONE x Number of Days in Delivery Year) / 30 Hours] / 12 Intervals

The applicable charge rate for the June 2022 PAI for those resources modeled in the AEP Zone (Rest of RTO LDA) for the 2022/2023 Delivery Year is shown in Table 6-37.[101]

Table 6-37 Nonperformance Charge Rate

Zone	LDA	Net CONE (ICAP)	Charge Rate
AEP	RTO	$247.26	$250.69

This charge rate is multiplied by the performance shortfall in each PAI to determine the nonperformance financial penalty for committed CP resources. The nonperformance charge is calculated as:[102]

*Nonperformance Charge = Performance Shortfall MW * Nonperformance Charge Rate*

Table 6-38 Nonperformance Charges

Day	Avg Shortfall (MW/Interval)	Charges
June 14, 2022	5.9	$99,787.16
June 15, 2022	18.4	$590,567.72
June 16, 2022	35.1	$422,337.72
Total		$1,112,692.60

Figure 6-3 through Figure 6-5 show the aggregate nonperformance charge, expected reduction value and actual reduction value, by interval, of demand resources dispatched during the PAI events on June 14 through June 16, 2022.

100 PJM. "Manual 18: Capacity Market," § 9.1.9, Rev. 55 (Feb. 9, 2023).
101 PJM, Planning Period Parameters for Base Residual Auction, <https://www.pjm.com/-/media/markets-ops/rpm/rpm-auction-info/2022-2023/2022-2023-planning-period-parameters-for-base-residual-auction.ashx> (Accessed Oct 6, 2022).
102 PJM. "Manual 18: Capacity Market," § 9.1.9, Rev. 55 (Feb. 9, 2023).

Figure 6-3 Nonperformance charges, expected and actual reduction values: June 14, 2022

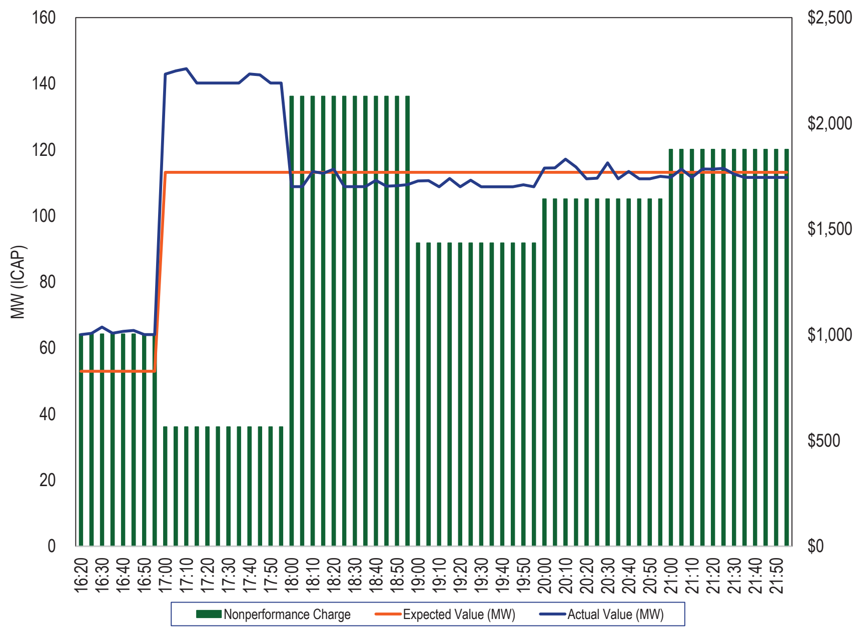


Figure 6-4 Nonperformance charges, expected and actual reduction values: June 15, 2022

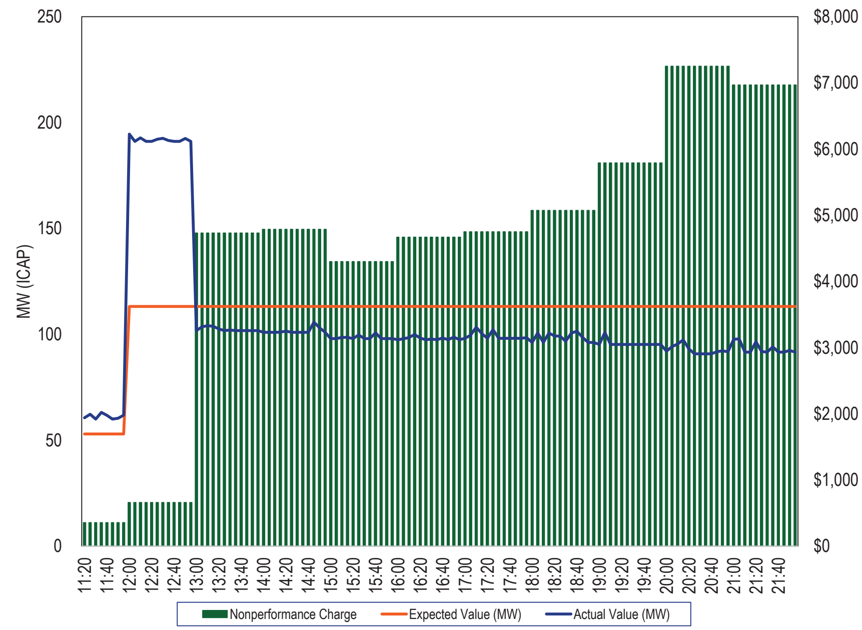
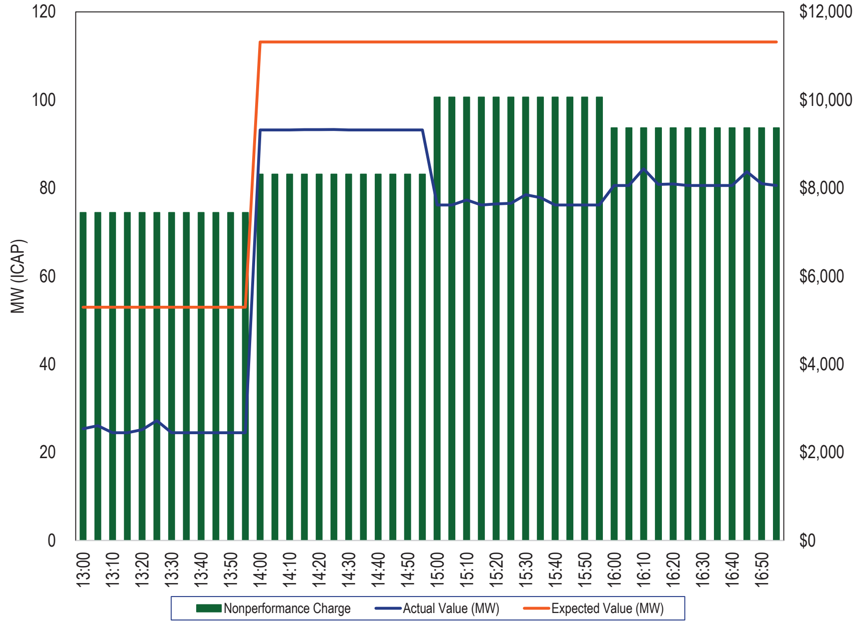


Figure 6-5 Nonperformance charges, expected and actual reduction values: June 16, 2022



Actual performance across all resources in the Emergency Action Area included the performance by resources that did not have a performance obligation, and over performance by some resources that did have a CP obligation. Demand Resources that are not capacity resources do not have an obligation to respond during an emergency and therefore do not contribute to the expected value. Table 6-39 shows the daily average actual performance as a percent of expected performance, with and without the contribution of resources that did not have an obligation to perform (non-CP resources).

The response overshot the expected response in the early part of each event and then leveled off or declined within each event. The performance declined significantly over the three day period.

Table 6-39 Daily average actual performance as a percent of expected performance: June 14, 15, and 16, 2022

Day	Including non-CP resources	Excluding non-CP resources
14-Jun-22	99.0%	96.3%
15-Jun-22	89.3%	86.8%
16-Jun-22	63.6%	62.3%

Bonus Performance

A resource with actual performance above its expected performance is assigned a share of the collected nonperformance charge revenues as a bonus performance credit. When calculating bonus megawatts, the actual performance of a dispatchable resource is capped at the megawatt level at which the resource was scheduled and dispatched by PJM during the performance assessment event.

The expected and actual performance calculations for bonus megawatt evaluations for load DR is:[103]

Expected Performance = CP Capacity Commitment (ICAP)

Actual Performance = Load Reduction + Reserve/Regulation Assignment

Table 6-40 Bonus performance credits: June 14, 15, and 16, 2022

Day	Avg Bonus (MW/Interval)	Credits
June 14, 2022	11.0	$99,787.16
June 15, 2022	13.3	$590,567.72
June 16, 2022	6.0	$422,337.72
Total		$1,112,692.60

Figure 6-6 through Figure 6-8 show the bonus MW and bonus credit, by interval, of demand resources dispatched during the PAI events on June 14 through June 16, 2022.

103 PJM. "Manual 18: Capacity Market," § 8.4A, Rev. 55 (Feb. 9, 2023).

Figure 6-6 Bonus performance by interval: June 14, 2022

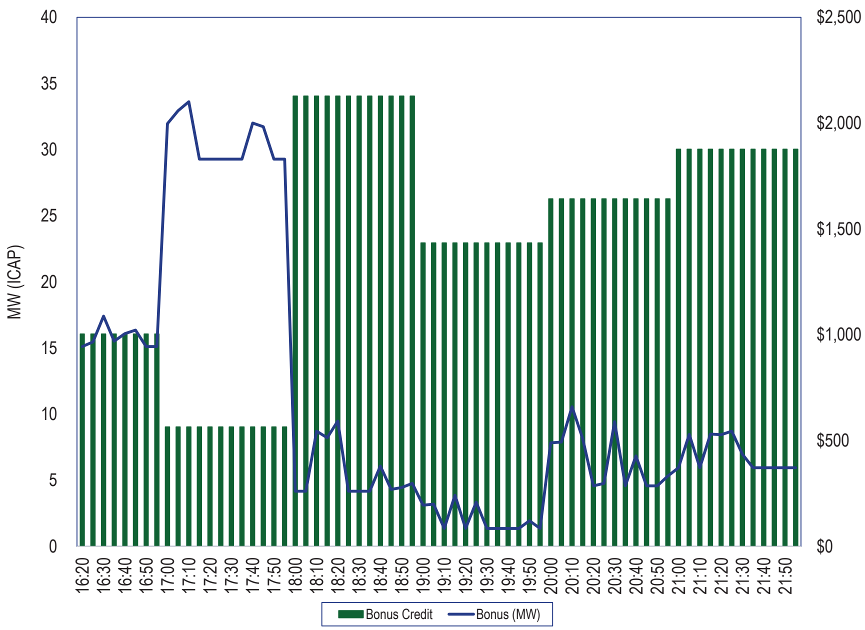


Figure 6-7 Bonus performance by interval: June 15, 2022

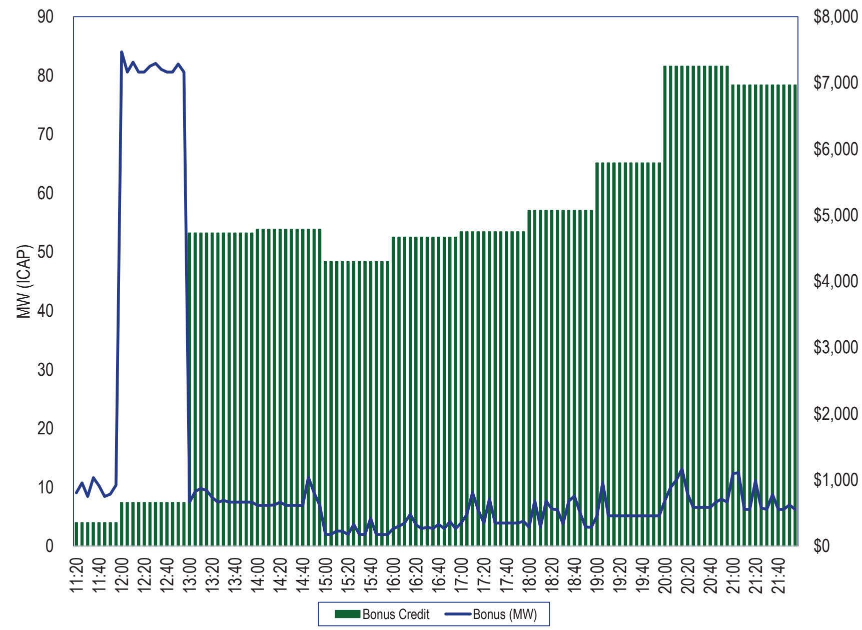
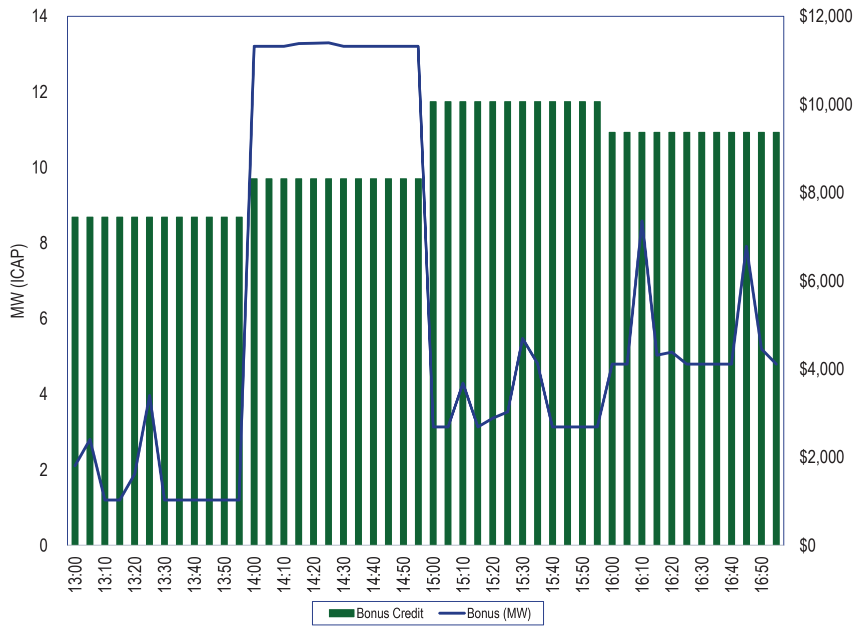


Figure 6-8 Bonus performance by interval: June 16, 2022



Emergency Energy Credits

Table 6-41 shows the distribution of registrations and associated MW in the emergency full option across ranges of minimum dispatch prices in the AEP Marion Load Management Subzone. The majority of participants, 79.2 percent of locations and 39.7 percent of nominated MW, had a minimum dispatch price between $1,550 and $1,849 per MWh, the maximum price allowed for the 2022/2023 Delivery Year. All registrations had a dispatch price above $1,000 per MWh. The shutdown cost of resources with $1,000 to $1,275 per MWh strike prices had the highest average at $166.68 per location and $176.37 per nominated MW.

Table 6-41 Distribution of registrations and associated MW in the full option across ranges of minimum dispatch price

Range of Strike Prices ($/MWh)	Locations	Percent of Total	Nominated MW (ICAP)	Percent of Total	Shutdown Cost per Location	Shutdown Cost per Nominated MW (ICAP)
$1,000-$1,275	69	19.1%	65.2	53.9%	$166.68	$176.37
$1,275-$1,550	6	1.7%	7.7	6.3%	$0.00	$0.00
$1,550-$1,849	286	79.2%	48.0	39.7%	$2.21	$13.17
Total	361	100.0%	120.9	100.0%	$168.89	$189.54

The relief provided by a demand resource eligible for emergency energy payments is equal to the estimated load that would have occurred (CBL) less the RT metered load. Table 6-42 shows the total emergency energy credits, by day, paid to demand response resources dispatched during the PAI events on June 14 through June 16, 2022.

Table 6-42 Emergency energy credits

Day	Credits
14-Jun-22	$80,311
15-Jun-22	$221,289
16-Jun-22	$45,571
Total	$347,171

Figure 6-9 through Figure 6-11 show the aggregate emergency energy credits, customer baseline (CBL) and metered load of demand resources dispatched during the PAI events on June 14 through June 16, 2022.

Figure 6-9 Emergency energy credits, CBL and metered load: June 14, 2022

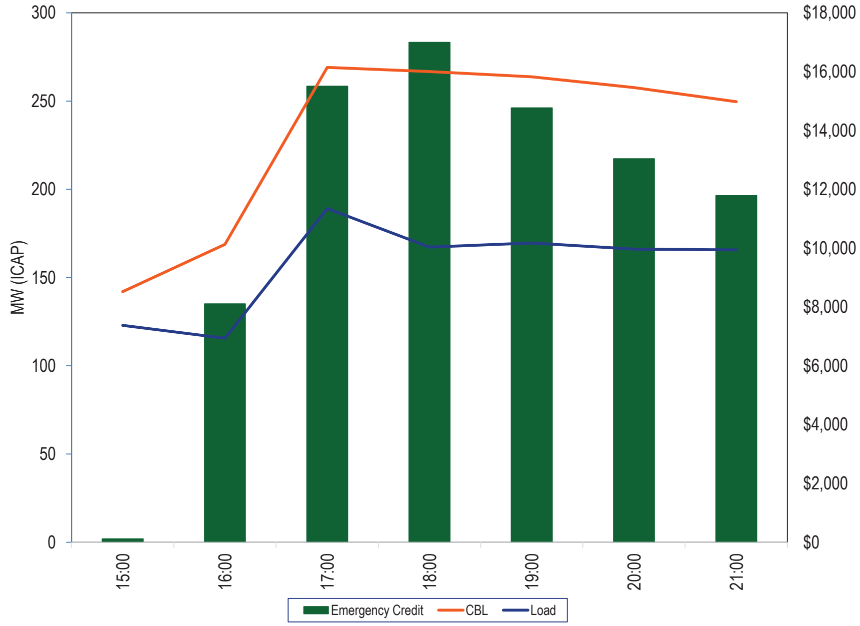


Figure 6-10 Emergency energy credits, CBL and metered load: June 15, 2022

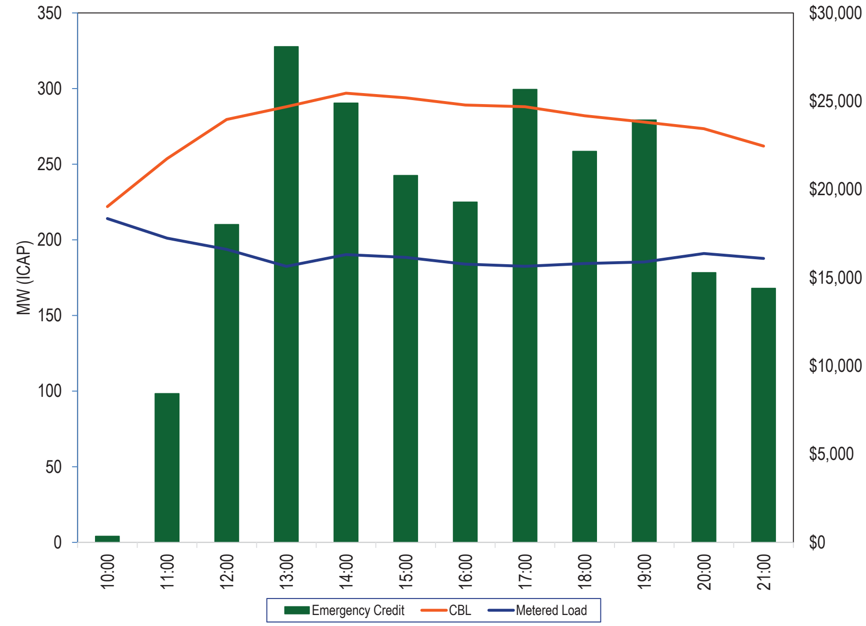
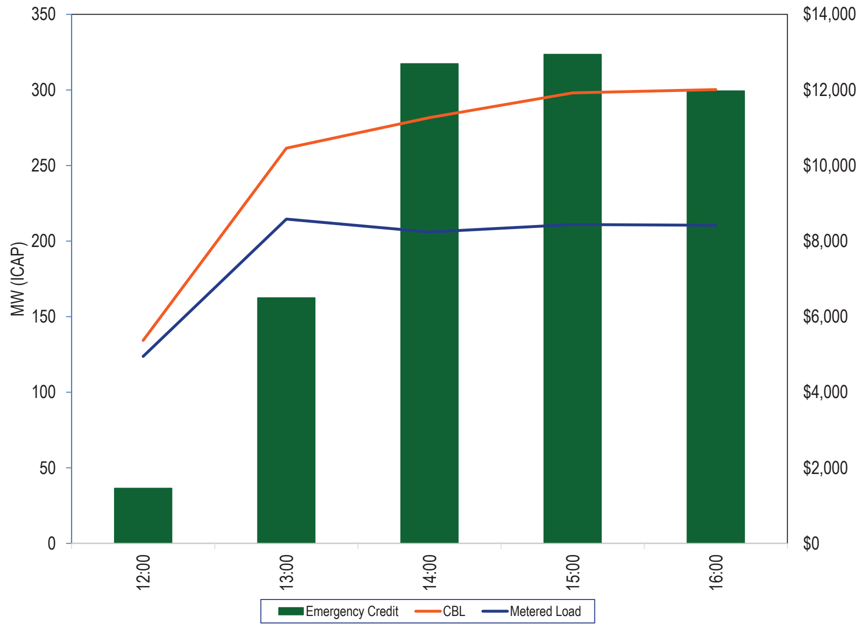


Figure 6-11 Emergency energy credits, CBL and metered load: June 16, 2022



In order to provide relief, a dispatched registration must be operating at a load level below their CBL. Table 6-43 through Table 6-45 show the numbers of registrations, and associated MW quantities, with load below versus above their CBL, by hour, during the PAI events.

Table 6-43 Registration performance vs CBL: June 14, 2022

	Below CBL		Above CBL	
Hour	Number of registrations	MW	Number of registrations	MW
15:00	99	29.8	57	10.0
16:00	183	57.2	36	2.6
17:00	213	84.2	31	2.0
18:00	215	102.9	39	0.9
19:00	225	97.6	35	0.9
20:00	225	96.2	33	1.9
21:00	216	89.2	34	2.7

Table 6-44 Registration performance vs CBL: June 15, 2022

	Below CBL		Above CBL	
Hour	Number of registrations	MW	Number of registrations	MW
10:00	111	13.6	57	5.4
11:00	200	56.0	35	1.8
12:00	239	89.4	35	1.2
13:00	263	109.1	26	0.9
14:00	256	110.3	39	1.0
15:00	260	109.1	31	0.9
16:00	263	108.8	26	1.0
17:00	257	109.1	28	0.9
18:00	252	101.2	33	1.0
19:00	255	95.8	30	1.0
20:00	238	85.9	33	1.3
21:00	224	78.0	30	1.8

Table 6-45 Registration performance vs CBL: June 16, 2022

	Below CBL		Above CBL	
Hour	Number of registrations	MW	Number of registrations	MW
12:00	118	12.7	53	1.9
13:00	214	49.3	35	1.1
14:00	245	78.4	28	0.7
15:00	260	89.7	26	0.3
16:00	266	92.9	21	0.8

Emergency Action Area

The Emergency Action Area for the June 14 through June 16, 2022 performance assessment events, the AEP_MARION Load Management Subzone, is defined by the zip codes shown in Table 6-46.[104]

Table 6-46 AEP_Marion Subzone zip codes

Zone	Subzone	Zip Code		
AEP	MARION	43015	43081	43064
AEP	MARION	43215	43146	43235
AEP	MARION	43125	43035	43220
AEP	MARION	43210	43082	43224
AEP	MARION	43207	43016	43202
AEP	MARION	43228	43026	43223
AEP	MARION	43213	43017	43212
AEP	MARION	43230	43240	43214
AEP	MARION	43085	43204	43232
AEP	MARION	43054	43004	43222
AEP	MARION	43219	43221	43162
AEP	MARION	43229	43209	43227
AEP	MARION	43201	43065	43211
AEP	MARION	43123	43068	43110
AEP	MARION	43205	43231	

Performance Assessment Event – Winter Storm Elliott

At 1730 EPT on December 23, 2022, PJM began issuing Load Management Reduction Actions. Quick Lead Time Pre-Emergency load management resources were required to fully implement their load reductions by 1800 EPT and were released between 2200 and 2215 EPT. Quick Lead Time Emergency load management resources were required to fully implement their load reductions by 1815 EPT and were released at 2130 EPT. Short Lead Time Pre-Emergency and Emergency load management resources were required to fully implement their load reductions by 1900 EPT and were released between 2130 and 2215 EPT. Long Lead Time load management resources were not deployed by PJM on December 23, 2022. The mandatory response time for Capacity Performance DR is limited to June through October and the following May from 10:00AM to 10:00PM EPT (1000 to 2200) and November through April from 6:00AM to 9:00PM EPT (0600 to 2100). Load management resources performing outside of these time periods are not subject to performance assessment but may be eligible for bonus payments.

At 0420 EPT on December 24, 2022, PJM began issuing Load Management Reduction Actions. Long Lead Time Pre-Emergency and Emergency load management resources were required to fully implement their load reductions by 0620 EPT and were released between 1930 and 2030 EPT. Short Lead Time Pre-Emergency and Emergency load management resources were required to fully implement their load reductions by 0600 EPT and were released between 1930 and 2030 EPT. Quick Lead Time Pre-Emergency and Emergency load management resources were required to fully implement their load reductions by 0600 EPT and were released between 1930 and 2030 EPT.

104 See "Load Management Subzones," <https://www.pjm.com/-/media/markets-ops/demand-response/subzone-definition-workbook.ashx> (Accessed June 14, 2022).

Table 6-47 Load management action event times: December 23 and 24, 2022

Date	Product Types	Lead Time	Notification Time (EPT)	Event Start (EPT)	Event End (EPT)	Zones
23-Dec-22	Pre-Emergency	Quick (30min)	1730	1800	2200	AECO, BGE, DPL, JCPL, METED, PECO, PENELEC, PEPCO, PPL
			1730	1800	2215	AEP, APS, ATSI, COMED, DAY, DEOK, DOM, DUQ, EKPC, PSEG, RECO
23-Dec-22	Emergency	Quick (30min)	1745	1815	2130	AEP, APS, ATSI, BGE, COMED, DAY, DEOK, DOM, DPL, DUQ, EKPC, JCPL, PECO, PENELEC, PEPCO
23-Dec-22	Emergency	Short (60min)	1800	1900	2130	AEP, ATSI, COMED, DOM, DPL, PENELEC
23-Dec-22	Pre-Emergency	Short (60min)	1800	1900	2200	AECO, BGE, DPL, JCPL, METED, PECO, PENELEC, PEPCO, PPL
			1800	1900	2215	AEP, APS, ATSI, COMED, DAY, DEOK, DOM, DUQ, EKPC, PSEG
24-Dec-22	Emergency	Long (120 min)	0420	0620	1930	COMED, DAY
			0420	0620	1945	APS, ATSI, DOM
			0420	0620	2015	AEP
			0420	0620	2030	BGE, DPL, PPL
24-Dec-22	Pre-Emergency	Long (120 min)	0420	0620	1930	COMED, DAY, DEOK, DUQ, EKPC
			0420	0620	1945	APS, ATSI, DOM
			0420	0620	2015	AEP, PSEG
			0420	0620	2030	AECO, BGE, DPL, JCPL, METED, PECO, PENELEC, PEPCO, PPL
24-Dec-22	Emergency	Short (60min)	0500	0600	1930	COMED
			0500	0600	1945	ATSI, DOM
			0500	0600	2015	AEP
			0500	0600	2030	DPL, PENELEC
24-Dec-22	Pre-Emergency	Short (60min)	0500	0600	1930	COMED, DAY, DEOK, DUQ, EKPC
			0500	0600	1945	APS, ATSI, DOM
			0500	0600	2015	AEP, PSEG
			0500	0600	2030	AECO, BGE, DPL, JCPL, METED, PECO, PENELEC, PEPCO, PPL
24-Dec-22	Emergency	Quick (30min)	0530	0600	1930	COMED, DAY, DEOK, DUQ, EKPC
			0530	0600	1945	APS, ATSI, DOM
			0530	0600	2015	AEP
			0530	0600	2030	BGE, DPL, JCPL, PECO, PENELEC, PEPCO
24-Dec-22	Pre-Emergency	Quick (30min)	0530	0600	1930	COMED, DAY, DEOK, DUQ, EKPC
			0530	0600	1945	APS, ATSI, DOM
			0530	0600	2015	AEP, PSEG, RECO
			0530	0600	2030	AECO, BGE, DPL, JCPL, METED, PECO, PENELEC, PEPCO, PPL

On a nominated ICAP basis, there were only 4,940.7 MW of Demand Response dispatched under the Load Management Reduction Actions on December 23, 2022, comprised of 4,565.9 MW of Quick Lead Time and 374.8 MW of Short Lead Time resources. Long Lead Time load management resources (3,721.0 MW) were not deployed by PJM on December 23, 2022, as a result of the combination of the 120 minute lead time and the fact that demand response performance obligations ended at 2100.

Table 6-48 Dispatched demand response resources by lead time: December 23, 2022

	Nominated ICAP (MW)			
Zone	Quick Lead Time	Short Lead Time	Long Lead Time	Total
AECO	45.2	4.3	0.0	49.5
AEP	729.7	121.0	0.0	850.6
APS	374.7	13.2	0.0	388.0
ATSI	388.1	30.3	0.0	418.3
BGE	116.9	6.1	0.0	123.1
COMED	1,125.9	38.4	0.0	1,164.2
DAY	119.9	5.8	0.0	125.7
DEOK	121.6	4.2	0.0	125.8
DOM	220.5	48.3	0.0	268.8
DPL	97.2	4.6	0.0	101.8
DUQ	77.4	7.2	0.0	84.6
EKPC	24.4	18.2	0.0	42.7
JCPL	80.4	3.3	0.0	83.7
METED	113.6	11.8	0.0	125.4
PECO	217.5	16.5	0.0	234.0
PENELEC	97.4	13.1	0.0	110.5
PEPCO	149.5	1.4	0.0	150.9
PPL	255.2	21.8	0.0	277.0
PSEG	208.2	5.3	0.0	213.5
RECO	2.7	0.0	0.0	2.7
Total	4,565.9	374.8	0.0	4,940.7

Included in the 4,940.7 MW of Demand Response resources dispatched on December 23, 2022, were 96.8 MW of Summer Only resources. Summer Only Demand Response resources are not obligated to respond during the months of November through April, but are eligible for bonus payments.

Table 6-49 Annual vs Summer Only Demand Response Resources: December 23, 2022

CP Commitment Type	Number of Registrations	MW (ICAP)
Annual	12,101	4,843.9
Summer Only	1,770	96.8
Total	13,871	4,940.7

On a nominated ICAP basis, there were 8,661.8 MW of Demand Response dispatched under the Load Management Reduction Actions on December 24, 2022, comprised of 4,565.9 MW of Quick Lead Time, 374.8 MW of Short Lead Time and 3,721.0 MW of Long Lead Time resources.

Table 6-50 Dispatched Demand Response Resources by Lead Time: December 24, 2022

	Nominated ICAP (MW)			
Zone	Quick Lead Time	Short Lead Time	Long Lead Time	Total
AECO	45.2	4.3	6.6	56.1
AEP	729.7	121.0	733.3	1,583.9
APS	374.7	13.2	235.2	623.1
ATSI	388.1	30.3	473.3	891.6
BGE	116.9	6.1	43.6	166.7
COMED	1,125.9	38.4	442.7	1,606.9
DAY	119.9	5.8	52.6	178.3
DEOK	121.6	4.2	91.0	216.8
DOM	220.5	48.3	493.6	762.4
DPL	97.2	4.6	153.8	255.6
DUQ	77.4	7.2	38.8	123.3
EKPC	24.4	18.2	218.9	261.6
JCPL	80.4	3.3	30.1	113.8
METED	113.6	11.8	57.3	182.7
PECO	217.5	16.5	82.9	316.9
PENELEC	97.4	13.1	141.9	252.4
PEPCO	149.5	1.4	180.4	331.3
PPL	255.2	21.8	196.0	473.0
PSEG	208.2	5.3	49.0	262.5
RECO	2.7	0.0	0.0	2.7
Total	4,565.9	374.8	3,721.0	8,661.8

Included in the 8,661.8 MW of Demand Response resources dispatched on December 24, 2022, were 487.9 MW of Summer Only resources. Summer Only Demand Response resources are not obligated to respond during the months of November through April, but are eligible for bonus payments.

Table 6-51 Annual vs Summer Only Demand Response Resources: December 24, 2022

CP Commitment Type	Number of Registrations	MW (ICAP)
Annual	14,532	8,173.9
Summer Only	1,781	487.9
Total	16,313	8,661.8

Table 6-52 and Table 6-53 shows the amount of nominated MW and registrations by lead time and reduction method dispatched for December 23 and December 24, 2022. Nominated MW are Pre-Emergency or Emergency

Load Response registrations used to satisfy a CSP's committed MW position for a delivery year.

Table 6-52 Demand Response Resources Called by Lead Time and Reduction Method: December 23, 2022

Product Type	Lead Time	Number of Registrations	Load Backed DR MW (ICAP)	Gen Backed DR MW (ICAP)	Total DR MW (ICAP)
Emergency	Long (120 min)	0	0.0	0.0	0.0
Emergency	Short (60 min)	10	3.8	17.2	21.0
Emergency	Quick (30 min)	229	17.6	174.1	191.7
Pre-Emergency	Long (120 min)	0	0.0	0.0	0.0
Pre-Emergency	Short (60 min)	307	321.3	32.6	353.8
Pre-Emergency	Quick (30 min)	13,325	3,971.9	402.3	4,374.2
Total		13,871	4,314.6	626.1	4,940.7

Table 6-53 Demand Response Resources Called by Lead Time and Reduction Method: December 24, 2022

Product Type	Lead Time	Number of Registrations	Load Backed DR MW (ICAP)	Gen Backed DR MW (ICAP)	Total DR MW (ICAP)
Emergency	Long (120 min)	60	13.4	133.5	146.9
Emergency	Short (60 min)	10	3.8	17.2	21.0
Emergency	Quick (30 min)	229	17.6	174.1	191.7
Pre-Emergency	Long (120 min)	2,382	3,091.7	482.4	3,574.1
Pre-Emergency	Short (60 min)	307	321.3	32.6	353.8
Pre-Emergency	Quick (30 min)	13,325	3,971.9	402.3	4,374.2
Total		16,313	7,419.8	1,242.0	8,661.8

Table 6-54 shows the distribution of registrations and associated MW in the emergency full option across ranges of minimum dispatch prices dispatched on December 23 and December 24, 2022. The majority of participants, 80.3 percent of locations and 51.7 percent of nominated MW, had a minimum dispatch price between $1,550 and $1,850 per MWh, the maximum price allowed for the 2022/2023 Delivery Year. Almost all registrations, 99.3 percent of locations and 97.8 percent of nominated MW have a dispatch price above $1,000 per MWh. The shutdown cost of resources with $1,000 to $1,275 per MWh strike prices have the highest average at $163.04 per location and $132.39 per nominated MW.

Table 6-54 Distribution of registrations and associated MW in the full option across ranges of minimum dispatch: December 23 and 24, 2022

Range of Strike Prices ($/MWh)	Locations	Percent of Total	Nominated MW (ICAP)	Percent of Total	Shutdown Cost per Location	Shutdown Cost per Nominated MW (ICAP)
$0-$1000	119	0.7%	187.1	2.2%	$80.65	$51.31
$1,000-$1,275	2,854	16.9%	3,514.7	41.7%	$163.04	$132.39
$1,275-$1,550	352	2.1%	370.9	4.4%	$42.65	$40.48
$1,550-$1,849	13,523	80.3%	4,353.4	51.7%	$41.89	$130.13
Total	16,848	100.0%	8,426.1	100.0%	$62.71	$125.38

The top four Curtailment Service Providers accounted for 86.6 percent of Demand Response MW dispatched under the Load Management Reduction Actions on December 23, 2022. The top for Curtailment Service Providers accounted for 78.2 percent of Demand Response MW dispatched under the Load Management Reduction Actions on December 24, 2022.

Performance

Any discussion of demand resource performance during a PAI must recognize the significant problems with the definition of performance for demand resources. As defined by PJM rules, performance, contrary to intuition, does not mean actually reducing load in response to a PJM request for demand resources. Performance means only that, on a net portfolio basis, the amount of capacity paid for in the capacity market (PLC) minus actual metered load is equal to the amount of demand side capacity sold in the capacity market (ICAP).

The standard reporting of demand side response is therefore misleading because it includes loads that were already lower for any reason as a response.

Immediately preceding the call for Load Management resources on December 23, 83 percent of registrations were already at load levels equal to or, below, their Winter Peak Loads. Immediately preceding the call for Load Management resources on December 24th, 90 percent of registrations were already at load levels equal to or, below, their Winter Peak Loads.

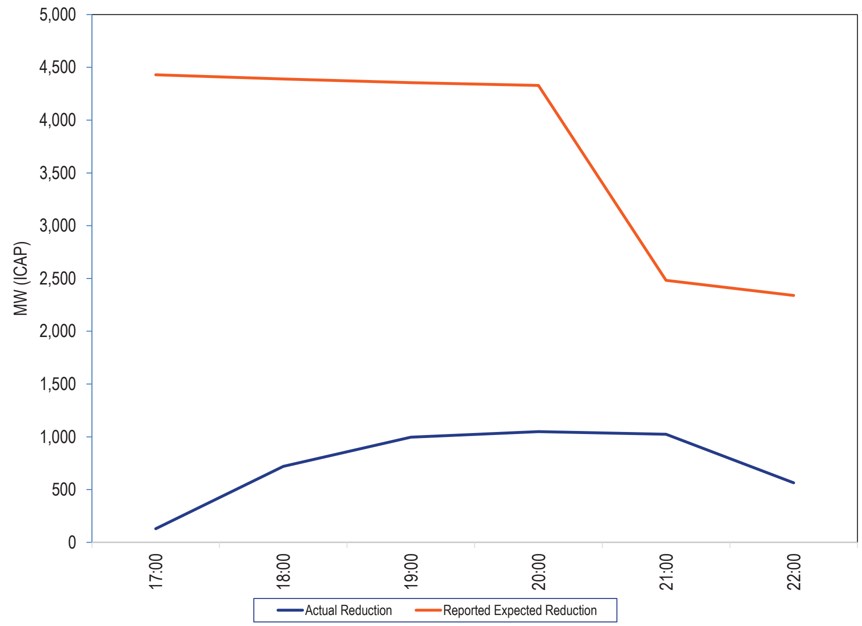
Expected Load Reduction Reporting

CSPs are required to report accurate expected real time energy load reductions by pre emergency/emergency status, lead time, product, and zone.[105] Expected real time energy load reductions are the amount of energy that the CSP expects will be reduced based on the difference between the CBL and expected load. If a registered location's load is already low and will not be reduced further, the CSP should report the expected reduction as zero. Reported expected load reductions do not affect emergency energy settlements. PJM uses the expected load reductions to determine the amount of DR to dispatch and to evaluate the expected response.

Prior to the start of a month, CSPs must upload expected reduction data for all Load Management registrations. Data should be reviewed daily throughout the month and updates, if any, are due by 1600 EPT on the day prior to each operating day. The review and update frequency increases to hourly (from 1000 thru 1900 EPT) when PJM has issued Maximum Emergency Generation or Load Management Alerts or Actions.

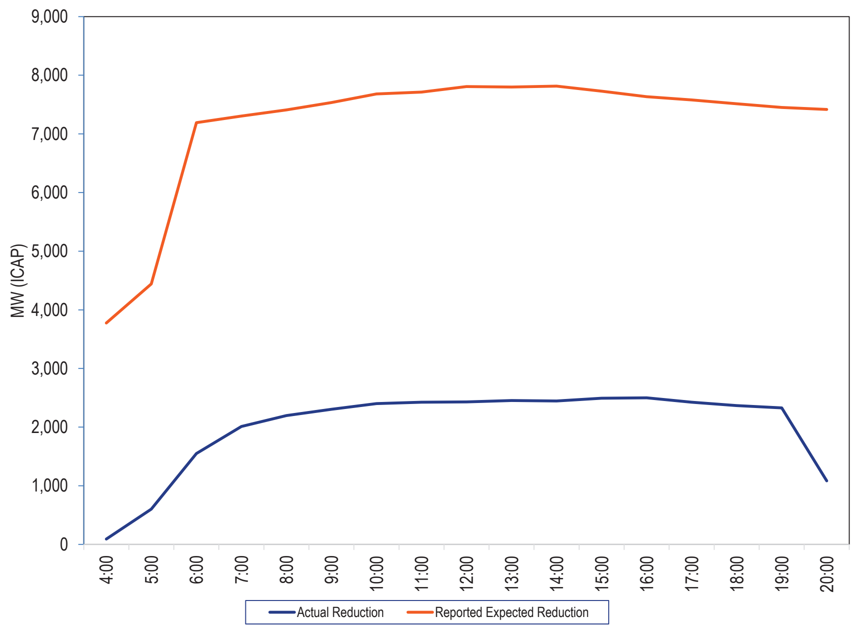
Figure 6-12 and Figure 6-13 show that the CSP forecasted real-time energy reductions were significantly greater than the actual energy load reductions provided on both December 23, 2022, and December 24, 2022.

Figure 6-12 Reported Expected vs Actual Reduction: December 23, 2022



105 See "Expected Reduction Upload Template," <https://pjm.com/-/media/etools/dr-hub/expected-reduction-reporting-template.ashx> (Accessed April 20, 2023).

Figure 6-13 Reported Expected vs Actual Reduction: December 24, 2022



Nonperformance Charges

Nonperformance charge rates are calculated on a modeled LDA basis for the relevant delivery year. The nonperformance charge rate for a specific resource is based on the Net CONE expressed in $/MW-day in ICAP for the LDA in which the resource is modeled and is calculated as:[106]

Nonperformance Charge Rate ($/MW-5-Minute Interval) = [(Net CONE x Number of Days in Delivery Year) / 30 Hours] / 12 Intervals

Table 6-55 shows the nonperformance charge rates for the 2022/2023 Delivery Year.

106 PJM. "Manual 18: Capacity Market," § 9.1.9, Rev. 55 (Feb. 9, 2023).

Table 6-55 Nonperformance Charge Rates for the 2022/2023 Delivery Year

LDA	Net CONE (ICAP)	Charge Rate
ATSI	$218.79	$221.83
ATSI-CLEVELAND	$218.79	$221.83
BGE	$214.87	$217.85
COMED	$235.27	$238.54
DAY	$214.82	$217.80
DEOK	$212.27	$215.22
DPL-SOUTH	$224.18	$227.29
EMAAC	$246.18	$249.60
MAAC	$232.67	$235.90
PEPCO	$246.34	$249.76
PPL	$237.69	$240.99
PS-NORTH	$254.80	$258.34
PSEG	$254.80	$258.34
RTO	$247.26	$250.69
SWMAAC	$230.61	$233.81

The charge rate is multiplied by the performance shortfall in each PAI to determine the nonperformance financial penalty for committed CP resources.[107] The nonperformance charge is calculated as:[108]

*Nonperformance Charge = Performance Shortfall MW * Nonperformance Charge Rate*

Table 6-56 Nonperformance Charges

Day	Charges
23-Dec-22	$875,477.34
24-Dec-22	$573,754.07
Total	$1,449,231.41

Figure 6-14 and Figure 6-15 show the aggregate nonperformance charge, expected reduction value and actual reduction value, by interval, of demand resources dispatched during the PAI events on December 23 through December 24, 2022.

107 Demand Response performance metrics, unless otherwise noted, exclude those committed to FRR and PRD.

108 The IMM identified a billing error in which PJM assessed nonperformance charges to Demand Resources on December 23rd beyond the end of their mandatory compliance time of 2100 EPT. PJM will correct the issue in the April monthly bill issued in May 2023. The IMM will update the penalty, bonus and overall performance metrics based on PJM's revised billing.

Figure 6-14 Nonperformance charges, expected and actual reduction values: December 23, 2022

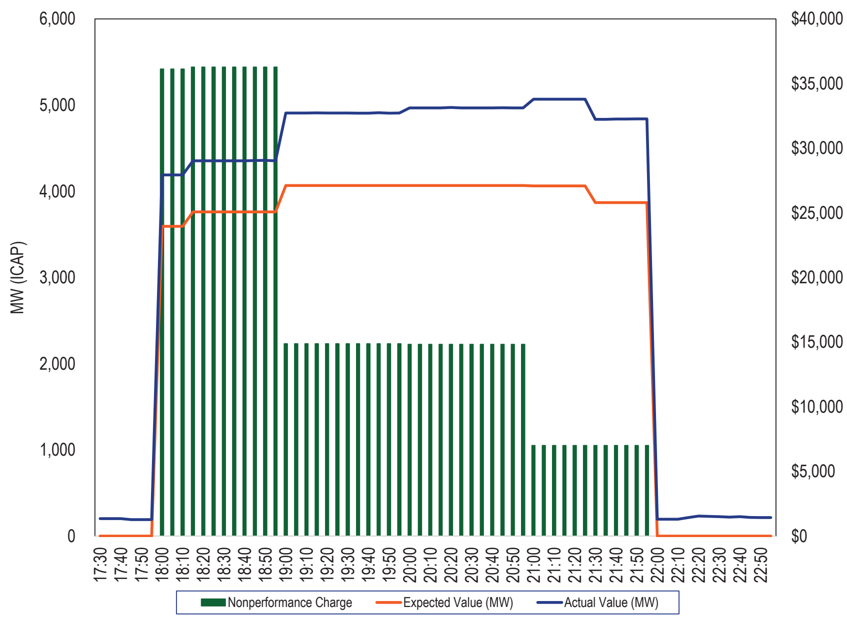
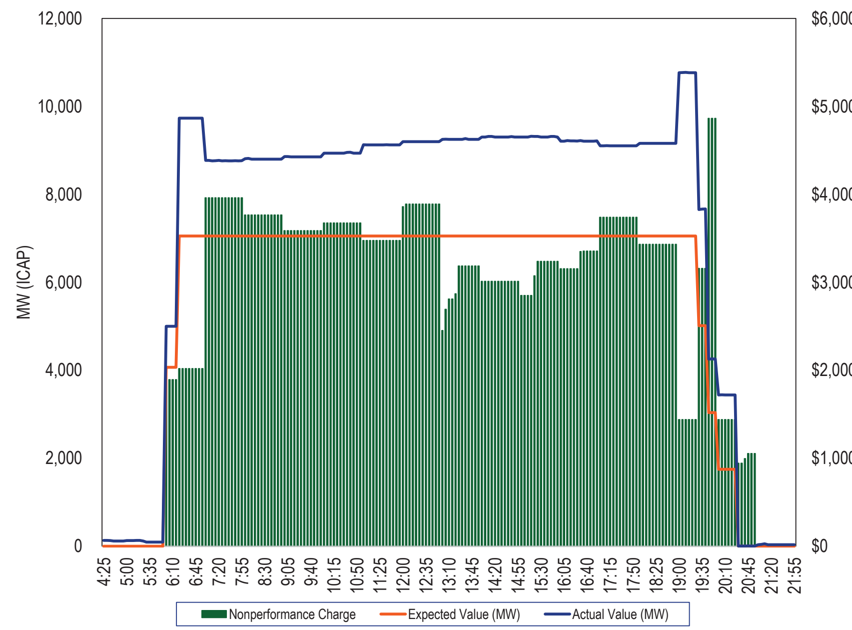


Figure 6-15 Nonperformance charges, expected and actual reduction values: December 24, 2022



Actual performance across all resources in the Emergency Action Area included the performance by resources that did not have a performance obligation, and over performance by some resources that did have a CP obligation. Demand Resources that are not capacity resources do not have an obligation to respond during an emergency and therefore do not contribute to the expected value. Table 6-57 shows the daily average actual performance as a percent of expected performance, with and without the contribution of resources that did not have an obligation to perform (non-CP resources).

Table 6-57 Daily average actual performance as a percent of expected performance: December 23 and 24, 2022

Day	Including non-CP resources	Excluding non-CP resources
23-Dec-22	120.9%	116.1%
24-Dec-22	132.0%	126.2%

Bonus Performance

A resource with actual performance above its expected performance is assigned a share of the collected nonperformance charge revenues as a bonus performance credit. When calculating bonus megawatts, the actual performance of a dispatchable resource is capped at the megawatt level at which the resource was scheduled and dispatched by PJM during the performance assessment event.

The expected and actual performance calculations for bonus megawatt evaluations for load DR is:[109]

Expected Performance = CP Capacity Commitment (ICAP)

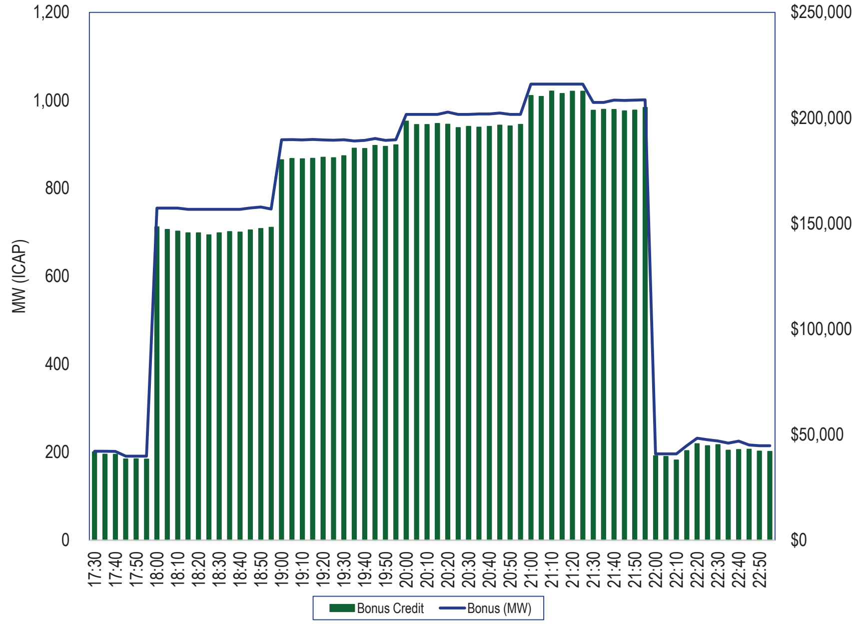
Actual Performance = Load Reduction + Reserve/Regulation Assignment

Table 6-58 Bonus Credits

Day	Bonus
23-Dec-22	$9,557,942.71
24-Dec-22	$69,341,298.87
Total	$78,899,241.58

Figure 6-6 through Figure 6-8 show the bonus MW and bonus credit, by interval, of demand resources dispatched during the PAI events on December 23 and 24, 2022.

Figure 6-16 Bonus performance by interval: December 23, 2022



109 PJM. "Manual 18: Capacity Market," § 8.4A, Rev. 55 (Feb. 9, 2023).

Figure 6-17 Bonus performance by interval: December 24, 2022

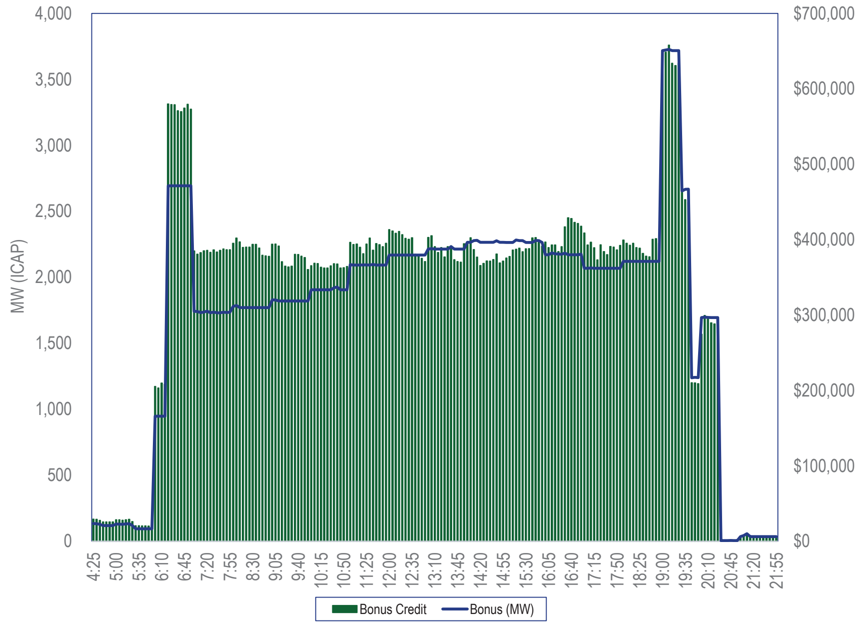
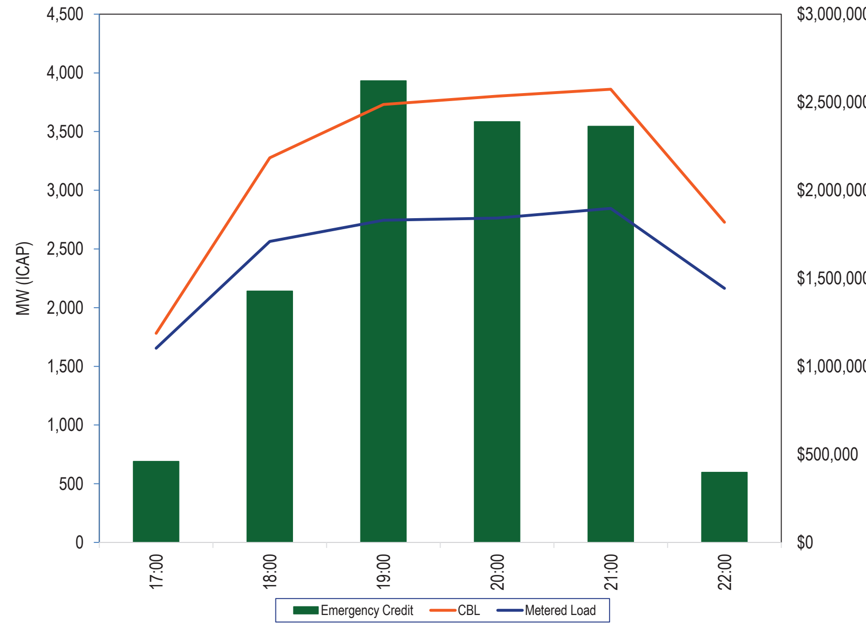


Figure 6-18 Emergency energy credits, CBL and metered load: December 23, 2022



Emergency Energy Credits

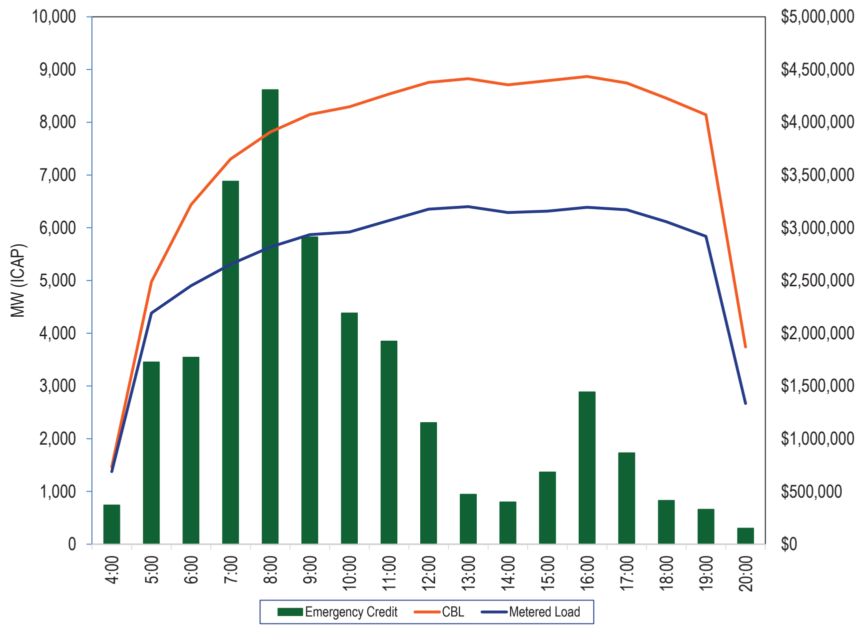
Table 6-59 shows the total emergency energy credits, by day, paid to demand response resources dispatched during the PAI events on December 23 and 24, 2022.

Table 6-59 Emergency energy credits: December 23 and 24, 2022

Day	Credits
23-Dec-22	$9,660,329
24-Dec-22	$24,560,940
Total	$34,221,268

Figure 6-18 and Figure 6-19 show the aggregate emergency energy credits, customer baseline and metered load of demand resources dispatched during the PAI events on December 23 and 24, 2022.

Figure 6-19 Emergency energy credits, CBL and metered load: December 24, 2022



In order to provide relief, a dispatched registration must be operating at a load level below their CBL. Table 6-60 and Table 6-61 show the numbers of registrations, and associated MW quantities, with load below versus above their CBL, by hour, during the PAI events.

Table 6-60 Registration performance vs CBL: December 23, 2022

	Below CBL		Above CBL	
Hour	Number of registrations	MW	Number of registrations	MW
17:00	1,726	186.2	1,066	57.0
18:00	3,487	768.9	1,059	48.9
19:00	4,101	1,050.6	1,047	54.2
20:00	4,325	1,112.3	1,126	63.3
21:00	4,369	1,087.5	1,190	64.1
22:00	2,604	618.1	874	53.3

Table 6-61 Registration performance vs CBL: December 24, 2022

	Below CBL		Above CBL	
Hour	Number of registrations	MW	Number of registrations	MW
4:00	4,852	657.7	1,554	56.7
6:00	6,200	1,587.3	1,416	38.1
7:00	7,186	2,048.5	1,309	36.7
8:00	8,129	2,254.6	1,137	57.6
9:00	8,825	2,345.7	1,096	40.6
10:00	9,386	2,437.8	1,078	35.6
11:00	9,719	2,463.3	1,113	38.0
12:00	9,900	2,494.3	1,186	63.5
13:00	10,106	2,507.4	1,208	53.9
14:00	10,252	2,514.8	1,209	67.8
15:00	10,336	2,553.1	1,214	59.6
16:00	10,414	2,551.6	1,163	51.9
17:00	10,187	2,478.7	1,292	53.7
18:00	10,216	2,440.3	1,124	72.4
19:00	9,954	2,392.7	1,111	64.3
20:00	5,020	1,134.1	526	50.1

PRD

PRD compliance is measured for a PRD registration upon declaration of a Performance Assessment Interval and when the PRD Curve associated with such registration in the PJM Real-time Energy Market has a price point where demand reduction is expected.[110] A PRD registration is not assessed when the PRD Curve associated with such registration in the real-time energy market indicates a price point where no demand reduction is expected at the real-time LMP recorded during the Performance Assessment Interval. The actual load reduction provided by the registration for the Performance Assessment Interval is calculated as the registration's Peak Load Contribution minus (the metered load multiplied by the loss factor). A load reduction will only be recognized if metered load multiplied by the loss factor is less than the Peak Load Contribution. The actual load reduction for a registration for a Performance Assessment Interval is capped at the Peak Load Contribution of the registration. For each registration in an Emergency Action Area, the Actual Performance is equal to the actual load reduction for such registration for the Performance Assessment Interval. The Actual Performance for a PRD Provider in the Emergency Action Area for the Performance Assessment Interval is

110 See "PJM Manual 18: PJM Capacity Market," § 3A.6.2A, Rev. 55 (Feb. 9, 2023).

equal to the sum of the Actual Performance of the PRD registrations that were measured for compliance for such Emergency Action Area and Performance Assessment Interval. The Expected Performance for a PRD Provider for the Emergency Action Area and Performance Assessment Interval is equal to the Nominal PRD Value committed by the PRD Provider in the Emergency Action Area, adjusted to account for any PRD registrations in the Emergency Action Area that were not subject to compliance measurement. The Performance Shortfall for a PRD Provider is calculated as the Expected Performance minus the Actual Performance. Unlike Demand Response resources registered in the full program option, PRD registrations are not eligible for emergency energy settlements.

Figure 6-20 PRD Nonperformance charges, expected and actual reduction values: December 23, 2022

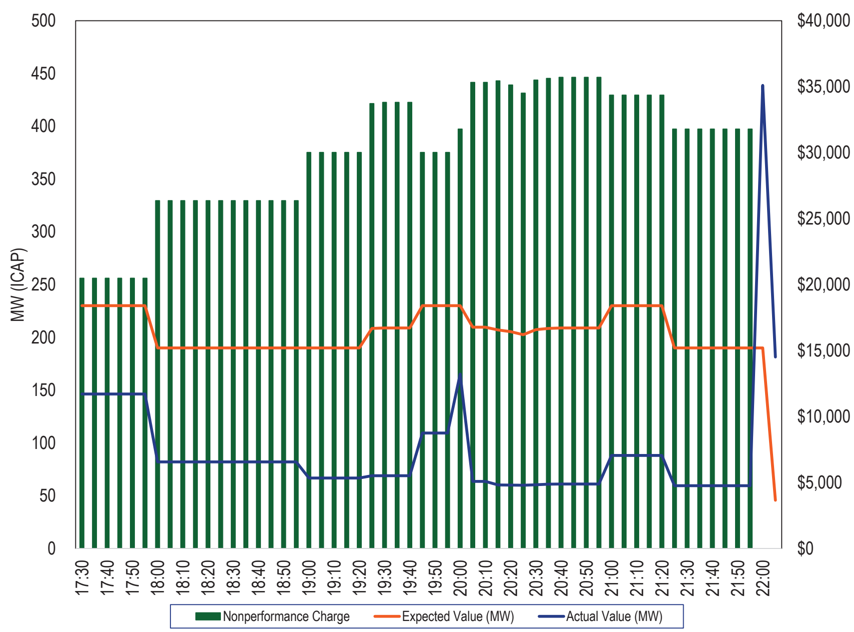


Figure 6-21 PRD Nonperformance charges, expected and actual reduction values: December 24, 2022

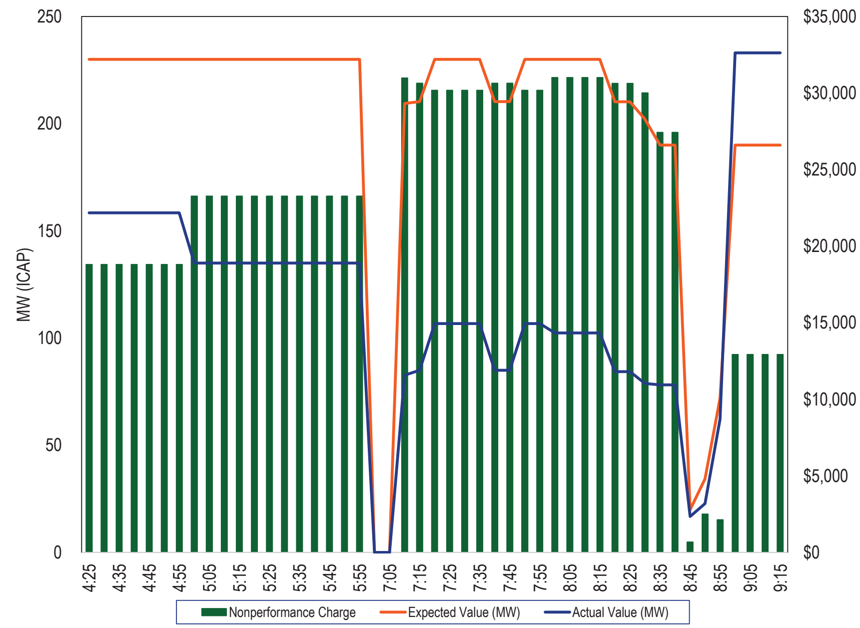


Table 6-62 shows the average daily performance of PRD resources on December 23 and 24, 2022.

Table 6-62 PRD Daily average actual performance as a percent of expected performance: December 23 and 24, 2022

Day	Percent Performance
23-Dec-22	49.7%
24-Dec-22	60.7%

Table 6-63 shows the daily nonperformance charges for PRD resources on December 23 and 24, 2022.

Table 6-63 PRD Nonperformance Charges: December 23 and 24, 2022

Day	Charges
23-Dec-22	$1,630,413.84
24-Dec-22	$1,042,231.96
Total	$2,672,645.80

Table 6-64 shows the daily bonus performance credits of PRD resources on December 23 and 24, 2022.

Table 6-64 PRD Bonus Credits: December 23 and 24, 2022

Day	Bonus
23-Dec-22	$93,208.55
24-Dec-22	$87,887.83
Total	$181,096.38

Energy Efficiency

The Expected Performance of an Energy Efficiency resource during a Performance Assessment Interval is determined as the resources' committed capacity without making any adjustment for the Forecast Pool Requirement. The actual performance of an Energy Efficiency resource with an RPM Capacity Performance commitment is not measured during a Performance Assessment Interval. The Actual Performance of an Energy Efficiency resource Energy Efficiency Resource is determined as the load reduction quantity approved by PJM subsequent to the pre-delivery year submittal of a post-installation M&V Report.[111] Any approved M&V quantity in excess of the resource's Expected Performance during a Performance Assessment event is treated as Actual Performance, and is eligible for bonus credits. No Energy Efficiency resources were assessed a nonperformance charge during December 23 and 24, 2022. Energy Efficiency resources in aggregate, were credited with 1,710.8 MW, 34.3 percent in excess of their RPM committed values per interval, during December 23 and 24, 2022. Due to the compressed RPM auction schedule, only two of the four otherwise eligible Energy Efficiency Installation period's resources were eligible to offer into the 2022/2023 RPM Base Residual Auction. The ineligible installation period resources were however eligible to be included in the participant's 2022/2023 Post-Installation M&V reports. This approved resource capability in excess of the participant's RPM commitment contributed to the excess Actual Performance, and subsequent bonus payments, to Energy Efficiency resources on December 23 and 24, 2022.

Table 6-65 EE Daily Percent Performance, Shortfall and Bonus: December 23 and 24, 2022

Day	Expected Performance MW	Actual Performance MW	Shortfall MW	Bonus MW	Bonus MW Percent of Expected Performance	Bonus Credits
23-Dec-22	4,987.5	6,698.3	0.0	1,710.8	34.3%	$22,607,295.74
24-Dec-22	4,987.5	6,698.3	0.0	1,710.8	34.3%	$68,925,583.76

111 See "PJM Manual 18: PJM Capacity Market," § 8.4A, Rev. 55 (Feb. 9, 2023).

Net Revenue

The Market Monitoring Unit (MMU) analyzed measures of PJM energy market structure, participant conduct and market performance. As part of the review of market performance, the MMU analyzed the net revenues earned by combustion turbine (CT), combined cycle (CC), coal plant (CP), diesel (DS), nuclear, solar, and wind generating units. The analysis also includes nuclear surplus/shortfall details for all the nuclear plants in the PJM market and an assessment of the units at risk of retirement in PJM.

Overview

Net Revenue

- Energy market net revenues are significantly affected by energy prices and fuel prices. Energy prices and fuel prices were significantly lower in the first three months of 2023 than in the first three months of 2022. The net effects were that in the first three months of 2023, average energy market net revenues decreased by 57 percent for a new combustion turbine (CT), 42 percent for a new combined cycle (CC), 89 percent for a new coal plant (CP), 41 percent for a new nuclear plant, 90 percent for a new diesel (DS), 34 percent for a new onshore wind installation, 50 percent for a new offshore wind installation and 49 percent for a new solar installation.
- The price of natural gas, Northern Appalachian coal and PRB coal decreased in the first three months of 2023. The marginal costs of a new CC and CT were less than the marginal cost of a new CP in the first three months of 2023.
- In the first three months of 2023, spark spreads increased in BGE, COMED, and Western Hub and dark spreads decreased. The volatility of both spark spreads and dark spreads decreased in BGE and PSEG compared to the first three months of 2022.
- All existing PJM nuclear plants are expected to cover their avoidable costs from energy and capacity market revenues in 2023, 2024, and 2025, without subsidies, with the exception of Davis Besse, a single unit nuclear plant, in 2023.

Recommendations

- The MMU recommends that the net revenue calculation used by PJM to calculate the net Cost of New Entry (CONE) and net ACR be based on a forward looking calculation of expected energy and ancillary services net revenues using forward prices for energy and fuel. (Priority: Medium. First reported 2019. Status: Not adopted.)

Conclusion

Wholesale electric power markets are affected by externally imposed reliability requirements. A regulatory authority external to the market makes a determination as to the acceptable level of reliability which is enforced through a requirement to maintain a target level of installed or unforced capacity. The requirement to maintain a target level of installed capacity can be enforced via a variety of mechanisms, including government construction of generation, full-requirement contracts with developers to construct and operate generation, state utility commission mandates to construct capacity, or capacity markets of various types. Regardless of the enforcement mechanism, the exogenous requirement to construct capacity in excess of what is constructed in response to energy market signals has an impact on energy markets. The reliability requirement results in maintaining a level of capacity in excess of the level that would result from the operation of an energy market alone. The result of that additional capacity is to reduce the level and volatility of energy market prices and to reduce the duration of high energy market prices. This, in turn, reduces net revenue to generation owners which reduces the incentive to invest. The exact level of both aggregate and locational excess capacity is a function of the calculation methods used by RTOs and ISOs. A basic purpose of the capacity market is allow all cleared capacity resources the opportunity to cover their net avoidable costs on an annual basis to ensure the economic sustainability of the reliable energy market.

Net Revenue

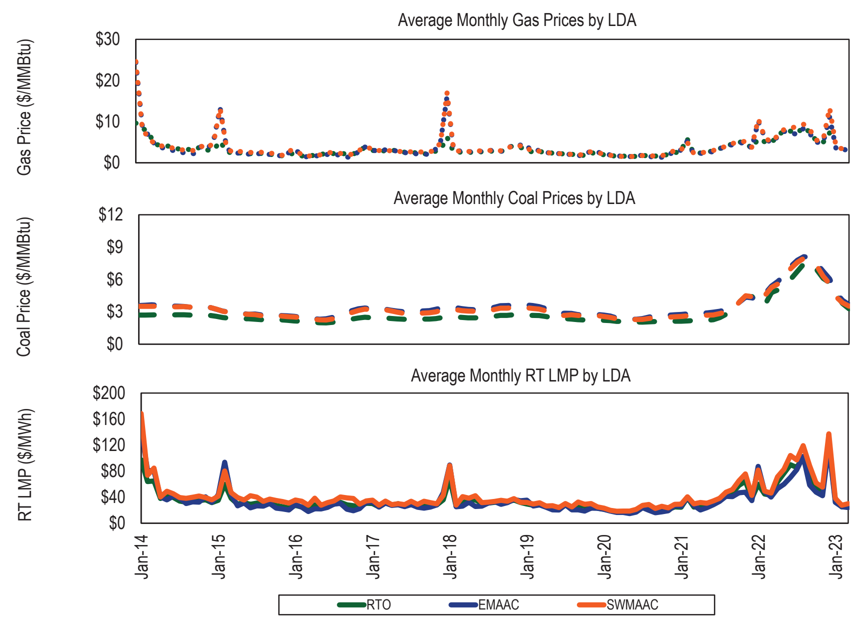
When compared to annualized fixed costs and avoidable costs, net revenue is an indicator of generation investment profitability, and thus is a measure of overall market performance as well as a measure of the incentive to invest in new generation and to maintain existing generation in PJM markets. Net revenue equals total revenue received by generators from PJM energy, capacity and ancillary service markets and from the provision of black start and reactive services and capability, less the short run marginal costs of energy production. In other words, net revenue is the amount that remains, after the short run marginal costs of energy production have been subtracted from gross revenue. Net revenue is the contribution to fixed costs, which include a return on investment, depreciation and income taxes, and to avoidable costs, which include long term and intermediate term operation and maintenance expenses.[1] Net revenue is the contribution to total fixed and avoidable costs received by generators from all PJM markets.

In a perfectly competitive, energy only market in long run equilibrium, net revenue from the energy market would be expected to equal the annualized fixed and avoidable costs for the marginal unit, including a competitive return on investment. The PJM market design includes other markets that contribute to the payment of fixed and avoidable costs. In PJM, the energy, capacity and ancillary service markets are all significant sources of revenue to cover the fixed and avoidable costs of generators, as are payments for the provision of black start and reactive services. Thus, in a perfectly competitive market in long run equilibrium, with energy, capacity and ancillary service revenues, net revenue from all sources would be expected to equal the annualized fixed and avoidable costs of generation for the marginal unit. Net revenue is a measure of whether generators are receiving competitive returns on invested capital and of whether market prices are high enough to encourage entry of new capacity and to encourage maintaining existing capacity. In actual wholesale power markets, where equilibrium seldom occurs, net revenue is expected to fluctuate above and below the equilibrium level based on actual conditions in all relevant markets.

1 Avoidable costs are sometimes referred to as going forward costs.

Net revenues are significantly affected by energy prices, fuel prices and capacity prices. PJM real-time energy market prices increased significantly in 2022. The real-time load-weighted average LMP in the first three months of 2023 decreased 40.2 percent from the first three months of 2022, from $52.25 per MWh to $31.26 per MWh. Gas prices and Northern App and PRB coal prices decreased in the first three months of 2023 compared to the first three months of 2022. The price of eastern natural gas was 57.5 percent lower, the price of western natural gas was 42.6 percent lower; the price of Northern Appalachian coal was 10.9 percent lower; the price of Central Appalachian coal was 11.3 percent higher; and the price of Powder River Basin coal was 27.6 percent lower (Figure 7-1).

Figure 7-1 Energy market net revenue factor trends: 2014 through March 2023



Spark Spreads and Dark Spreads

The spark or dark spread is defined as the difference between the LMP received for selling power and the cost of fuel used to generate power, converted to a cost per MWh. The spark spread compares power prices to the cost of gas and the dark spread compares power prices to the cost of coal. The spread is a measure of the approximate difference between revenues and marginal costs and is an indicator of net revenue and profitability.

$$Spread\left(\frac{\$}{MWh}\right) = LMP\left(\frac{\$}{MWh}\right) - Fuel\ Price\left(\frac{\$}{MMBtu}\right) * Heat\ Rate\left(\frac{MMBtu}{MWh}\right)$$

Spread volatility is a result of fluctuations in LMP and the price of fuel. Spreads can be positive or negative.

In the first three months of 2023, the change in spark spreads and dark spreads compared to the first three months of 2022 differed by zone. The volatility of both spark spreads and dark spreads also differed by zone.

Table 7-1 shows average peak hour spreads by year and Table 7-2 shows the associated standard deviations.

Table 7-1 Peak hour spark and dark spreads ($/MWh)

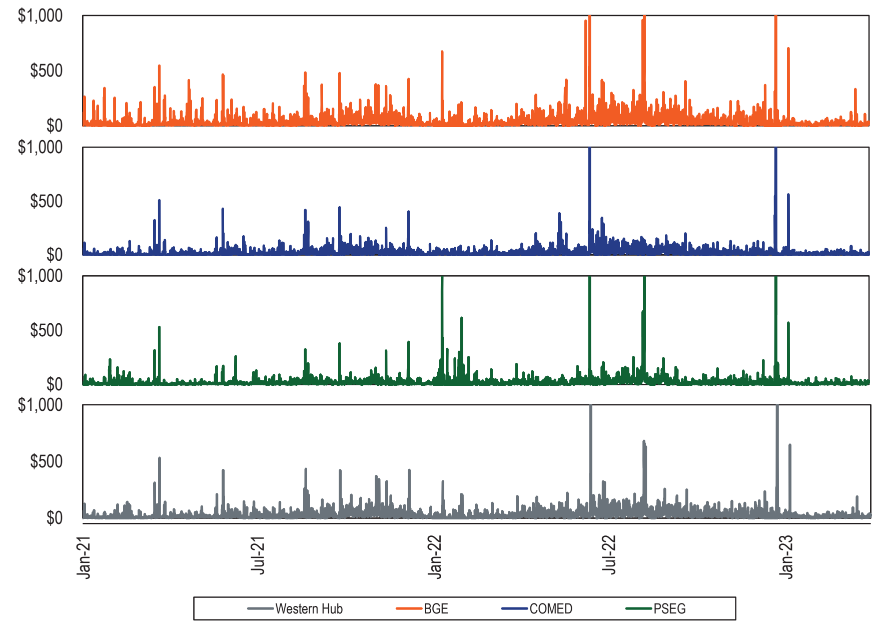
	BGE		COMED		PSEG		Western Hub	
Jan-Mar	Spark	Dark	Spark	Dark	Spark	Dark	Spark	Dark
2022	$11.97	$15.19	$11.19	$12.42	$13.30	$18.86	$6.70	$11.42
2023	$15.58	($6.23)	$11.28	$3.99	$7.48	($17.49)	$11.13	($9.06)
Percent change	30%	(141%)	1%	(68%)	(44%)	(193%)	66%	(179%)

Table 7-2 Peak hour spark and dark spread standard deviation ($/MWh)

	BGE		COMED		PSEG		Western Hub	
Jan-Mar	Spark	Dark	Spark	Dark	Spark	Dark	Spark	Dark
2022	$34.9	$38.0	$14.6	$15.0	$60.4	$67.5	$30.4	$26.7
2023	$29.8	$28.0	$20.1	$20.4	$28.0	$20.5	$35.1	$23.4
Percent change	(15%)	(26%)	37%	36%	(54%)	(70%)	16%	(13%)

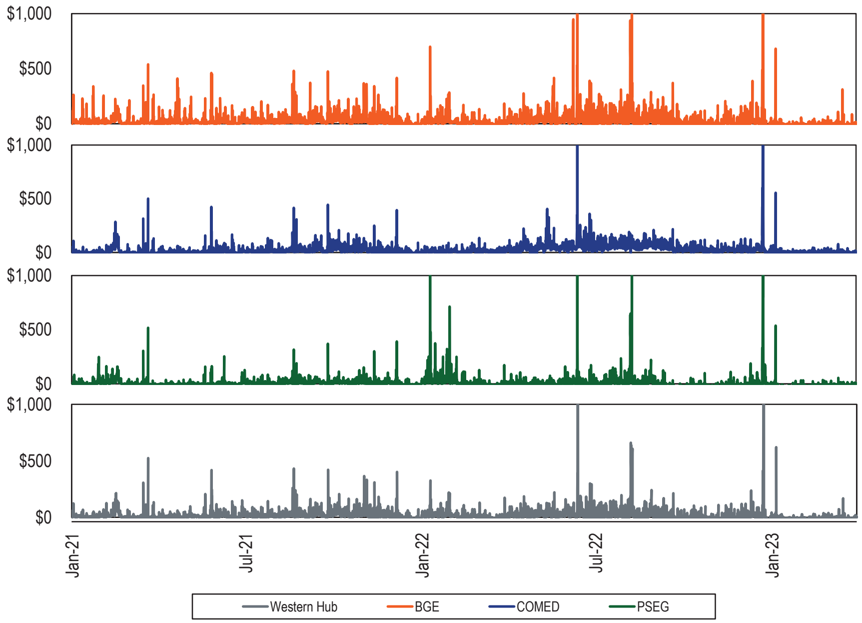
Figure 7-2 shows the hourly spark spread for peak hours for BGE, COMED, PSEG, and Western Hub.

Figure 7-2 Hourly spark spread (gas) for peak hours ($/MWh): 2021 through March 2023[2]



2 Spark spreads use a combined cycle heat rate of 7,000 Btu/kWh, zonal hourly LMPs and daily gas prices; Chicago City Gate for COMED, Zone 6 non-NY for BGE, Zone 6 NY for PSEG, and Texas Eastern M3 for Western Hub.

Figure 7-3 Hourly dark spread (coal) for peak hours ($/MWh): 2021 through March 2023[3]



Theoretical Energy Market Net Revenue

The net revenues presented in this section are theoretical as they are based on explicitly stated assumptions about how a new unit with specific characteristics would operate under economic dispatch. The economic dispatch uses technology specific operating constraints in the calculation of a new unit's operations and potential net revenue in PJM markets.

Analysis of energy market net revenues for a new unit includes eight power plant configurations:

- The CT plant is a single GE Frame 7HA.02 CT with an installed capacity of 360.1 MW, equipped with evaporative coolers, and selective catalytic reduction (SCR) for NO_x reduction.
- The CC plant includes two single shaft 1x1 GE Frame 7HA.02 CTs, each with a single combustion turbine, heat recovery steam generator, and steam turbine with a total installed capacity of 1,182 MW, equipped with SCR for NOx reduction, dry cooling, duct burners, and a firm gas transportation contract instead of dual-fuel capability.
- The CP is a subcritical steam unit with an installed capacity of 600.0 MW, equipped with selective catalytic reduction system (SCR) for NO_x control, a flue gas desulphurization (FGD) system with chemical injection for SO_x and mercury control, and a bag-house for particulate control.
- The DS plant is a single oil fired CAT 2 MW unit with an installed capacity of 2.0 MW using New York Harbor ultra low sulfur diesel.
- The nuclear plant includes two units and related facilities using the Westinghouse AP1000 technology with an installed capacity of 2,200 MW.
- The onshore wind installation includes 104 Siemens 2.9 MW wind turbines with an installed capacity of 301.6 MW.
- The offshore wind installation includes of 40 Siemens 10.0 MW wind turbines with an installed capacity of 400.0 MW.
- The solar installation is a 472 acre ground mounted tracking solar farm with an installed AC capacity of 200 MW.
- The battery storage unit is a 2.5 MW ICAP, 10 hour battery capable of providing 2.5 MWh for 10 hours, or 25 MWh.

Net revenue calculations for the CT, CC and CP include the hourly effect of actual local ambient air temperature on plant heat rates and generator output for each of the three plant configurations.[4] [5] Plant heat rates account for the efficiency changes and corresponding cost changes resulting from ambient air temperatures.

3 Dark spreads use a heat rate of 10,000 Btu/kWh, zonal hourly LMPs, daily coal prices, and average transportation costs by coal type; Powder River Basin coal for COMED, Northern Appalachian coal for BGE and Western Hub, and Central Appalachian coal for PSEG.

4 Hourly ambient conditions supplied by DTN.

5 Heat rates provided by Pasteris Energy, Inc. No load costs are included in the dispatch price since each unit type is dispatched at full load for every economic hour resulting in a single offer point.

CO_2, NO_x and SO_2 emission allowance costs are included in the hourly plant dispatch cost, the short run marginal cost.[6] CO_2, NO_x and SO_2 emission allowance costs were obtained from daily spot cash prices.[7]

The class average equivalent availability factor for each type of plant was calculated from PJM data and incorporated into all revenue calculations.[8]

Zonal net revenues reflect average zonal LMP and fuel costs based on locational fuel indices and zone specific delivery charges.[9] The delivered fuel cost for natural gas reflects the zonal, daily delivered price of natural gas from a specific pipeline and is from published commodity daily cash prices, with a basis adjustment for transportation costs.[10] The delivered cost of coal reflects the zone specific, delivered price of coal and was developed from the published prompt month prices, adjusted for rail transportation costs.[11] Net revenues are calculated for all zones except OVEC.[12]

Short run marginal cost includes fuel costs, emissions costs, and the short run marginal component of VOM costs.[13] [14] Average short run marginal costs are shown, including all components, in Table 7-3 and the short run marginal component of VOM is also shown separately.

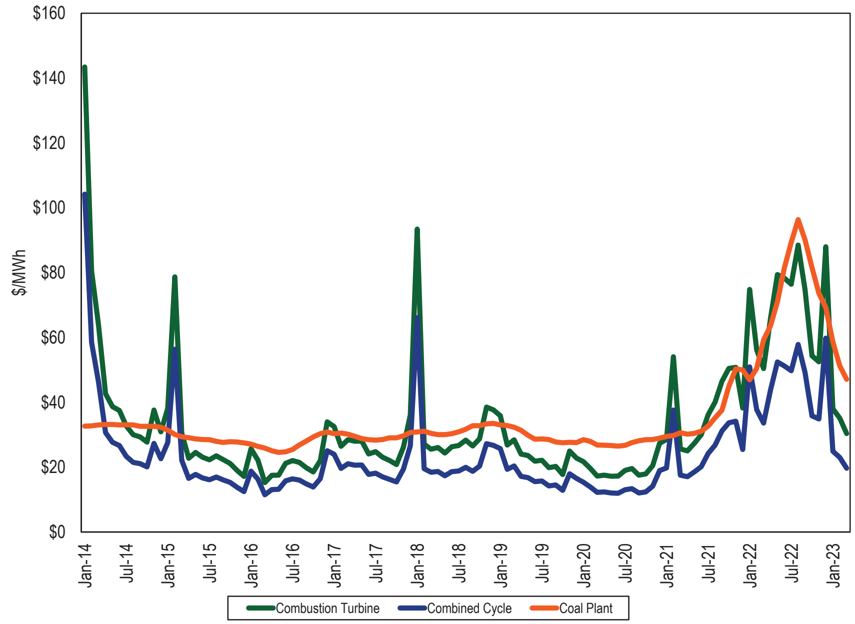
Table 7-3 Average short run marginal costs: January through March, 2023

Unit Type	Short Run Marginal Costs ($/MWh)	Heat Rate (Btu/kWh)	VOM ($/MWh)
CT	$34.50	9,241	$0.54
CC	$22.53	6,369	$0.88
CP	$52.31	9,250	$5.64
DS	$349.12	9,660	$0.25
Nuclear	$0.00	NA	$0.00
Wind	$0.00	NA	$0.00
Wind (off shore)	$0.00	NA	$0.00
Solar	$0.00	NA	$0.00

6 CO_2 emission allowance costs only included for states participating in RGGI.
7 CO_2, NO_x and SO_2 emission daily prompt prices obtained from Evolution Markets, Inc.
8 Outage figures obtained from the PJM eGADS database.
9 Startup fuel burns and emission rates provided by Pasteris Energy, Inc. Startup station power consumption costs were obtained from the station service rates published quarterly by PJM and netted against the MW produced during startup at the preceding applicable hourly LMP. All starts associated with combined cycle units are assumed to be warm starts.
10 Gas daily cash prices obtained from Platts.
11 Coal prompt month prices obtained from Platts.
12 The Ohio Valley Electric Corporation (OVEC) includes a generating plant in Ohio and a generating plant in Indiana, and high voltage transmission lines, but does not occupy a single geographic footprint like the other control zones.
13 Fuel costs are calculated using the daily spot price and may not equal what individual participants actually paid.
14 VOM rates provided by Pasteris Energy, Inc.

A comparison of the monthly average short run marginal cost of the theoretical CT, CC and CP plants since 2014 shows that, on average, the short run marginal costs of the CC plant have been less than those of the CP plant but the costs of the CC plant have been more volatile than the costs of the CP plant as a result of the higher volatility of gas prices compared to coal prices (Figure 7-4). In the first three months of 2023, the marginal costs of a new CC and CT were less than the marginal cost of a new CP. The marginal costs are based on spot fuel costs. Individual generation plants may have contracts for coal that differ significantly from spot prices.

Figure 7-4 Average short run marginal costs: 2014 through March 2023



The net revenue measure does not include the potentially significant contribution from the explicit or implicit sale of the option value of physical units or from bilateral agreements to sell output at a price other than the PJM day-ahead or real-time energy market prices, e.g., a forward price.

Gas prices, coal prices, and energy prices are reflected in new unit capacity factors. Table 7-4 shows the average capacity factor for new units. The capacity factor for a new CP declined in the first three months of 2023 compared to the first three months of 2022, while the capacity factors for other unit types were relatively unchanged.

Table 7-4 Average capacity factor: January through March, 2014 through 2023

Jan-Mar	CT	CC	CP	DS	Nuclear	On Shore Wind	Solar
2014	44%	69%	74%	11%	91%	33%	11%
2015	61%	74%	67%	8%	92%	32%	13%
2016	74%	79%	43%	1%	92%	33%	14%
2017	51%	73%	41%	0%	94%	34%	13%
2018	58%	80%	40%	7%	94%	37%	13%
2019	47%	79%	27%	1%	93%	33%	13%
2020	53%	80%	6%	0%	93%	31%	12%
2021	38%	78%	33%	2%	93%	31%	12%
2022	37%	71%	36%	1%	92%	33%	14%
2023	42%	70%	5%	0%	92%	34%	13%

New Entrant Combustion Turbine

Energy market net revenue was calculated for a new CT plant economically dispatched by PJM. It was assumed that the CT plant had a minimum run time of two hours. The unit was first committed day ahead in profitable blocks of at least two hours, including start costs. If the unit was not already committed day ahead, it was run in real time in standalone profitable blocks of at least two hours, or any additional profitable hours bordering the profitable day-ahead or real-time block.

The new entrant CT is larger and more efficient than most CTs currently operating in PJM. The new entrant CT energy market net revenue results must therefore be interpreted carefully when comparing to existing CTs which are generally smaller and less efficient than the newest CT technology used by the new entrant CT.

New entrant CT plant energy market net revenues were lower in all zones except Duquesne in the first three months of 2023, as a result of the relative changes in energy prices and gas costs (Table 7-5).

Table 7-5 Energy net revenue for a new entrant gas fired CT under economic dispatch: January through March, 2014 through 2023 (Dollars per installed MW-year)[15]

	Jan-Mar										
Zone	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	Change in 2023 from 2022
ACEC	$37,754	$12,776	$9,793	$5,094	$6,806	$7,471	$971	$2,519	$11,918	$1,661	(86%)
AEP	$54,108	$28,204	$17,445	$8,061	$29,985	$9,977	$8,681	$7,386	$18,450	$12,006	(35%)
APS	$67,470	$45,378	$13,746	$6,445	$36,990	$5,997	$2,111	$7,015	$12,276	$4,548	(63%)
ATSI	$35,579	$23,015	$15,204	$8,790	$37,051	$10,895	$8,913	$9,488	$17,233	$9,724	(44%)
BGE	$43,148	$12,147	$19,132	$8,307	$12,933	$5,766	$2,798	$8,385	$13,858	$4,694	(66%)
COMED	$22,324	$11,462	$8,184	$3,957	$10,373	$4,047	$4,209	$3,279	$8,827	$5,674	(36%)
DAY	$32,065	$20,233	$15,044	$7,517	$31,940	$11,113	$10,418	$13,494	$20,461	$11,641	(43%)
DOM	$39,668	$16,211	$18,598	$7,708	$15,105	$7,316	$5,139	$6,897	$14,534	$9,607	(34%)
DPL	$38,694	$12,217	$6,240	$3,796	$6,485	$3,500	$502	$11,557	$17,751	$3,779	(79%)
DUKE	$29,200	$17,892	$14,061	$6,192	$38,188	$9,490	$8,904	$12,405	$18,741	$10,373	(45%)
DUQ	$14,592	$9,130	$14,864	$4,724	$8,098	$3,872	$4,217	$4,285	$5,038	$8,498	69%
EKPC	$49,038	$21,659	$15,107	$6,595	$20,778	$8,411	$7,595	$7,901	$18,881	$10,263	(46%)
JCPLC	$41,229	$14,179	$7,559	$6,342	$7,018	$6,376	$990	$2,333	$10,957	$1,248	(89%)
MEC	$41,388	$20,993	$13,828	$7,711	$11,234	$5,616	$5,731	$5,579	$19,247	$8,052	(58%)
PE	$81,671	$58,960	$24,023	$9,259	$38,540	$10,088	$8,218	$11,934	$32,468	$16,271	(50%)
PECO	$41,809	$20,891	$12,766	$6,174	$9,570	$5,030	$4,413	$3,208	$13,760	$3,265	(76%)
PEPCO	$46,885	$13,007	$10,982	$6,099	$11,383	$4,754	$1,679	$5,131	$11,822	$3,323	(72%)
PPL	$148,553	$84,974	$20,750	$10,291	$45,447	$7,185	$4,138	$8,804	$29,476	$10,985	(63%)
PSEG	$52,790	$28,103	$15,489	$8,117	$10,758	$6,631	$1,107	$5,878	$14,460	$1,227	(92%)
REC	$31,162	$16,289	$7,900	$5,640	$5,466	$5,443	$1,063	$11,775	$16,528	$2,374	(86%)
PJM	$58,381	$24,386	$14,036	$6,841	$19,707	$6,949	$4,590	$7,463	$16,334	$6,961	(57%)

15 The energy net revenues presented for the PJM area in this section are calculated using the zonal average LMP.

New Entrant Combined Cycle

Energy market net revenue was calculated for a new CC plant economically dispatched by PJM. It was assumed that the CC plant had a minimum run time of four hours. The unit was first committed day ahead in profitable blocks of at least four hours, including start costs.[16] The unit was allowed to extend its run in real time if it was profitable to do so.

New entrant CC plant energy market net revenues were lower in all zones except Duquesne in the first three months of 2023 as a result of the relative changes in energy prices and gas costs (Table 7-6).

Table 7-6 Energy net revenue for a new entrant CC under economic dispatch: January through March, 2014 through 2023 (Dollars per installed MW-year)[17]

	Jan-Mar										
Zone	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	Change in 2023 from 2022
ACEC	$51,917	$21,960	$14,306	$11,375	$14,242	$15,408	$6,819	$5,979	$10,640	$2,507	(76%)
AEP	$63,214	$35,476	$22,439	$14,388	$37,756	$18,967	$14,283	$15,052	$35,234	$23,196	(34%)
APS	$79,776	$54,676	$25,811	$14,554	$46,949	$16,367	$11,146	$16,400	$26,257	$11,206	(57%)
ATSI	$40,769	$31,458	$20,863	$14,986	$43,292	$19,794	$14,512	$18,167	$34,136	$20,842	(39%)
BGE	$57,866	$21,830	$30,782	$16,487	$23,231	$15,669	$12,098	$17,573	$20,653	$12,067	(42%)
COMED	$24,402	$18,254	$13,878	$8,627	$14,200	$9,662	$9,432	$7,621	$18,334	$12,905	(30%)
DAY	$35,604	$28,773	$20,747	$14,010	$39,039	$20,098	$15,942	$22,208	$37,397	$23,140	(38%)
DOM	$50,643	$25,250	$24,676	$14,431	$20,823	$16,407	$11,574	$14,918	$27,562	$20,929	(24%)
DPL	$50,053	$18,656	$12,529	$5,832	$9,759	$4,873	$1,035	$12,599	$19,035	$4,944	(74%)
DUKE	$31,977	$26,108	$19,795	$12,381	$44,259	$18,282	$14,548	$20,636	$35,334	$21,642	(39%)
DUQ	$18,875	$12,222	$19,372	$10,714	$16,465	$10,886	$10,477	$10,658	$13,879	$19,578	41%
EKPC	$57,036	$29,698	$20,355	$12,851	$29,400	$16,973	$13,540	$16,353	$34,287	$21,574	(37%)
JCPLC	$57,370	$23,293	$12,163	$12,537	$14,412	$14,416	$6,985	$5,854	$8,413	$2,250	(73%)
MEC	$52,805	$30,724	$17,860	$13,766	$19,939	$13,968	$11,572	$13,004	$23,692	$18,534	(22%)
PE	$91,359	$59,225	$26,285	$15,380	$44,819	$19,147	$13,657	$20,663	$49,248	$26,930	(45%)
PECO	$55,336	$32,397	$16,873	$12,277	$19,415	$12,909	$10,228	$9,982	$14,538	$10,537	(28%)
PEPCO	$61,605	$23,012	$23,146	$13,829	$19,546	$14,156	$9,378	$11,412	$16,309	$7,411	(55%)
PPL	$145,442	$78,794	$23,078	$15,942	$49,592	$14,995	$9,980	$16,706	$45,065	$21,346	(53%)
PSEG	$72,991	$40,604	$19,821	$14,442	$21,129	$15,592	$7,789	$9,595	$10,796	$1,998	(81%)
REC	$47,382	$23,878	$12,337	$11,761	$11,689	$13,869	$7,363	$13,360	$16,154	$3,327	(79%)
PJM	$100,026	$31,814	$19,856	$13,029	$26,998	$15,122	$10,618	$13,937	$24,848	$14,343	(42%)

16 All starts associated with combined cycle units are assumed to be warm starts.
17 The energy net revenues presented for the PJM area in this section represent the zonal average energy net revenues.

New Entrant Coal Plant

Energy market net revenue was calculated for a new CP plant economically dispatched by PJM. It was assumed that the CP plant had a minimum run time of eight hours. The unit was first committed day ahead in profitable blocks of at least eight hours, including start costs. The unit was allowed to extend its run in real time if it was profitable to do so.

New entrant CP plant energy market net revenues were lower in all zones in the first three months of 2023 as a result of lower energy prices and the cost of coal by zone (Table 7-7).

Table 7-7 Energy net revenue for a new entrant CP: January through March, 2014 through 2023 (Dollars per installed MW-year)[18]

	Jan-Mar										
Zone	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	Change in 2023 from 2022
ACEC	$107,792	$40,142	$3,745	$1,178	$28,013	$3,213	$0	$3,211	$5,701	$1,156	(80%)
AEP	$70,724	$23,058	$7,315	$8,104	$25,314	$5,842	$351	$12,337	$10,989	$163	(99%)
APS	$82,000	$30,858	$1,920	$4,398	$26,869	$2,782	$0	$5,977	$6,193	$472	(92%)
ATSI	$78,044	$24,868	$5,334	$9,185	$26,251	$5,642	$53	$9,672	$10,838	$219	(98%)
BGE	$128,660	$45,329	$11,098	$4,976	$32,968	$3,458	$73	$9,554	$14,019	$1,774	(87%)
COMED	$64,187	$19,375	$3,431	$6,920	$9,375	$5,332	$66	$10,349	$28,239	$9,363	(67%)
DAY	$70,902	$23,143	$5,092	$7,464	$22,695	$5,662	$325	$14,065	$10,634	$153	(99%)
DOM	$109,653	$50,579	$13,462	$5,084	$35,980	$5,116	$384	$11,383	$27,235	$2,377	(91%)
DPL	$131,152	$53,979	$6,464	$3,809	$33,539	$4,046	$6	$11,384	$15,972	$2,539	(84%)
DUKE	$65,351	$20,425	$4,336	$5,817	$27,387	$4,441	$101	$12,785	$9,633	$156	(98%)
DUQ	$61,547	$16,396	$4,816	$7,965	$25,460	$4,699	$27	$8,965	$8,870	$196	(98%)
EKPC	$65,318	$19,528	$3,750	$5,444	$16,902	$3,322	$55	$11,588	$10,416	$140	(99%)
JCPLC	$112,807	$41,387	$2,170	$1,327	$28,138	$2,940	$0	$3,215	$6,930	$1,080	(84%)
MEC	$124,027	$49,857	$4,409	$4,229	$33,221	$4,316	$525	$8,670	$27,403	$2,199	(92%)
PE	$92,537	$38,559	$4,808	$3,194	$24,903	$3,599	$35	$9,517	$22,472	$1,435	(94%)
PECO	$105,865	$39,385	$1,975	$1,169	$27,881	$2,761	$0	$4,481	$12,370	$1,416	(89%)
PEPCO	$106,471	$32,196	$2,494	$1,062	$25,772	$1,733	$0	$5,175	$7,692	$1,581	(79%)
PPL	$105,142	$38,500	$2,031	$1,309	$27,030	$1,634	$0	$4,743	$12,199	$1,361	(89%)
PSEG	$141,330	$60,005	$5,254	$3,272	$31,064	$4,276	$0	$4,396	$14,469	$1,060	(93%)
REC	$138,906	$61,121	$4,860	$3,287	$29,033	$4,966	$0	$8,166	$17,485	$1,264	(93%)
PJM	$98,121	$36,434	$4,938	$4,459	$26,890	$3,989	$100	$8,482	$13,988	$1,505	(89%)

18 The energy net revenues presented for the PJM area in this section represent the zonal average energy net revenues.

New Entrant Nuclear Plant

Energy market net revenue was calculated assuming that the nuclear plant was dispatched day ahead by PJM for all available plant hours. The unit runs for all hours and output reflects the class average equivalent availability factor.[19]

New entrant nuclear plant energy market net revenues were lower in all zones in the first three months of 2023 as a result of lower energy prices (Table 7-8).

Table 7-8 Energy net revenue for a new entrant nuclear plant: January through March, 2014 through 2023 (Dollars per installed MW-year)[20]

	Jan-Mar										
Zone	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	Change in 2023 from 2022
ACEC	$211,846	$115,640	$48,725	$58,221	$94,760	$60,423	$37,593	$55,190	$102,930	$56,302	(45%)
AEP	$138,944	$79,965	$52,917	$58,719	$81,608	$58,767	$40,931	$61,127	$98,835	$62,838	(36%)
APS	$160,110	$97,683	$55,589	$60,569	$92,244	$60,182	$40,555	$60,590	$104,382	$65,144	(38%)
ATSI	$147,452	$81,034	$52,730	$60,761	$85,634	$60,612	$41,365	$60,525	$97,928	$63,126	(36%)
BGE	$221,336	$117,188	$72,903	$67,346	$105,209	$64,215	$43,501	$68,896	$119,282	$72,975	(39%)
COMED	$121,565	$67,311	$47,298	$54,992	$57,591	$52,559	$38,015	$57,449	$80,606	$53,568	(34%)
DAY	$138,517	$77,939	$52,634	$59,527	$80,788	$60,909	$42,956	$65,079	$101,345	$65,545	(35%)
DOM	$190,797	$112,959	$62,378	$63,021	$102,639	$62,157	$40,958	$63,882	$117,847	$69,318	(41%)
DPL	$224,316	$126,346	$61,073	$63,399	$100,951	$60,325	$38,079	$69,344	$114,601	$58,279	(49%)
DUKE	$131,887	$74,773	$51,588	$57,464	$86,563	$58,821	$41,383	$63,281	$99,134	$63,972	(35%)
DUQ	$127,759	$70,888	$52,008	$59,245	$84,336	$58,959	$41,119	$58,969	$94,431	$61,765	(35%)
EKPC	$131,844	$73,721	$50,862	$56,994	$72,894	$57,057	$40,988	$61,600	$100,027	$63,035	(37%)
JCPLC	$218,343	$116,586	$46,100	$59,689	$94,793	$59,323	$37,785	$54,901	$106,644	$57,171	(46%)
MEC	$207,794	$111,544	$46,218	$59,539	$95,281	$59,162	$38,361	$57,647	$115,503	$62,582	(46%)
PE	$170,103	$98,672	$50,863	$58,911	$87,072	$59,494	$39,506	$59,862	$109,907	$63,736	(42%)
PECO	$209,402	$114,373	$45,162	$57,657	$94,548	$57,937	$36,838	$54,446	$102,865	$54,044	(47%)
PEPCO	$217,980	$114,824	$65,798	$65,002	$102,966	$63,377	$42,283	$65,197	$117,467	$70,944	(40%)
PPL	$208,338	$113,104	$46,485	$59,062	$91,735	$55,819	$36,183	$55,245	$105,871	$58,024	(45%)
PSEG	$234,034	$124,111	$48,419	$60,394	$97,373	$61,330	$37,947	$60,042	$112,895	$58,399	(48%)
REC	$231,133	$125,393	$47,495	$60,714	$94,786	$61,717	$38,526	$66,729	$120,425	$62,121	(48%)
PJM	$182,175	$100,703	$52,862	$60,061	$90,189	$59,657	$39,744	$61,000	$106,146	$62,144	(41%)

19 The annual class average equivalent availability factor was used in the calculation of energy market net revenues.
20 The energy net revenues presented for the PJM area in this section represent the zonal average energy net revenues because fuel costs for nuclear units are included in the NEI nuclear costs.

New Entrant Diesel

Energy market net revenue was calculated for a DS plant economically dispatched by PJM in real time.

New entrant DS plant energy market net revenues were lower in all zones in the first three months of 2023 as a result of lower energy prices (Table 7-9).

Table 7-9 Energy market net revenue for a new entrant DS: January through March, 2014 through 2023 (Dollars per installed MW-year)

	Jan-Mar										
Zone	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	Change in 2023 from 2022
ACEC	$32,171	$11,172	$1,895	$131	$9,687	$1,171	$19	$760	$5,193	$211	(96%)
AEP	$14,072	$2,816	$316	$18	$3,182	$228	$121	$1,129	$526	$277	(47%)
APS	$17,632	$6,050	$391	$64	$5,853	$225	$79	$718	$727	$286	(61%)
ATSI	$13,724	$2,448	$256	$70	$2,327	$203	$127	$688	$524	$310	(41%)
BGE	$48,591	$9,773	$2,207	$843	$11,091	$588	$226	$2,349	$3,729	$333	(91%)
COMED	$11,036	$1,626	$152	$0	$603	$164	$96	$1,304	$392	$218	(44%)
DAY	$13,842	$2,296	$269	$17	$1,401	$246	$143	$1,362	$531	$286	(46%)
DOM	$42,074	$9,235	$1,282	$390	$13,183	$385	$145	$1,180	$3,572	$320	(91%)
DPL	$35,919	$12,810	$1,670	$732	$11,197	$1,176	$19	$10,663	$6,142	$792	(87%)
DUKE	$13,051	$1,892	$399	$11	$2,689	$207	$121	$1,597	$489	$271	(45%)
DUQ	$12,607	$2,016	$255	$72	$2,615	$181	$152	$715	$511	$291	(43%)
EKPC	$14,101	$2,087	$493	$10	$1,485	$205	$122	$1,861	$505	$272	(46%)
JCPLC	$32,414	$11,631	$456	$209	$10,693	$1,131	$17	$707	$4,934	$222	(95%)
MEC	$31,497	$10,905	$425	$167	$10,574	$357	$109	$903	$5,658	$263	(95%)
PE	$15,656	$5,284	$266	$95	$4,610	$94	$145	$696	$618	$255	(59%)
PECO	$31,741	$11,085	$421	$173	$9,516	$1,071	$21	$734	$5,107	$204	(96%)
PEPCO	$50,549	$8,848	$1,182	$394	$11,047	$466	$168	$1,124	$3,910	$319	(92%)
PPL	$32,438	$11,661	$397	$199	$8,376	$82	$23	$755	$2,701	$245	(91%)
PSEG	$31,987	$11,287	$520	$205	$9,756	$1,481	$19	$1,131	$5,266	$220	(96%)
REC	$29,526	$12,515	$507	$200	$8,823	$1,325	$21	$5,124	$5,167	$222	(96%)
PJM	$29,787	$7,372	$688	$200	$6,935	$549	$94	$1,775	$2,810	$291	(90%)

New Entrant Onshore Wind Installation

Energy market net revenues for an onshore wind installation were calculated hourly assuming the unit generated at the average capacity factor of all operating wind units in the zone with an installed capacity greater than 3 MW.[21]

Onshore wind energy market net revenues were lower in the first three months of 2023 as a result of lower energy prices.

Table 7-10 Energy market net revenue for an onshore wind installation (Dollars per installed MW-year): January through March, 2014 through 2023

	Jan-Mar										
Zone	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	Change in 2023 from 2022
AEP	$45,406	$26,566	$21,777	$22,697	$38,566	$23,727	$13,525	$18,024	$35,754	$23,155	(35%)
APS	$53,819	$33,489	$19,391	$24,579	$39,477	$19,314	$13,487	$17,251	$33,236	$23,017	(31%)
COMED	$39,397	$23,379	$16,746	$21,821	$24,103	$20,127	$11,754	$18,216	$27,570	$19,795	(28%)
PE	$66,094	$43,528	$21,076	$25,331	$41,510	$20,090	$12,783	$17,270	$34,758	$20,404	(41%)

New Entrant Offshore Wind Installation

Energy market net revenues for an offshore wind installation were calculated hourly assuming the unit generated at a 40 percent capacity factor.[22]

Offshore wind energy market net revenues were lower in the first three months of 2023 as a result of lower energy prices.

Table 7-11 Energy market net revenue for an offshore wind installation (Dollars per installed MW-year): January through March, 2014 through 2023

	Jan-Mar										
Zone	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	Change in 2023 from 2022
ACEC	$85,651	$48,092	$21,071	$24,600	$40,720	$26,205	$16,368	$22,664	$47,210	$22,908	(51%)
DOM	$88,644	$45,463	$25,403	$26,668	$45,330	$25,880	$17,241	$27,419	$51,619	$28,667	(44%)
DPL	$91,499	$52,339	$24,464	$26,906	$43,334	$25,814	$16,556	$33,490	$54,108	$24,587	(55%)

21 Net revenues are calculated for zones in which there are sufficient operating units to determine capacity factor for a new entrant unit.
22 PJM Planning. ELCC Class Ratings for 2023/2024. (Eff. December 16, 2021). <https://www.pjm.com/-/media/planning/res-adeq/elcc/elcc-class-ratings-for-2023-2024-bra.ashx>.

New Entrant Solar Installation

Energy market net revenues for a solar installation were calculated hourly assuming the unit was generating at the average hourly capacity factor of operating solar units in the zone with an installed capacity greater than 3 MW.[23]

Solar energy market net revenues were higher in the first three months of 2023 as a result of lower energy prices.

Table 7-12 Energy market net revenue for a solar installation (Dollars per installed MW-year): January through March, 2014 through 2023

	Jan-Mar										
Zone	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	Change in 2023 from 2022
ACEC	$21,536	$13,316	$5,993	$6,914	$10,062	$7,282	$4,438	$5,187	$11,826	$5,528	(53%)
DOM	-	-	$11,030	$12,432	$16,098	$10,274	$6,915	$9,150	$19,472	$11,503	(41%)
DPL	-	-	$8,621	$9,593	$12,531	$8,845	$5,452	$7,086	$13,396	$7,862	(41%)
JCPLC	$20,041	$10,930	$4,953	$6,140	$8,959	$6,448	$3,984	$4,666	$10,983	$5,145	(53%)
PSEG	$19,380	$14,236	$6,048	$6,760	$10,192	$7,759	$4,895	$6,894	$13,527	$5,994	(56%)

Historical New Entrant CC Revenue Adequacy

Total unit net revenues include energy and capacity market revenues. Analysis of the total unit revenues of theoretical new entrant CCs for three representative locations shows that CC units that entered the PJM markets in 2007 have covered 90 percent of their total costs in the BGE Zone and 87 percent of total costs in the PSEG Zone, and 49 percent of total costs in the COMED Zone, including the return on and of capital, on a cumulative basis. The analysis also shows that theoretical new entrant CCs that entered the PJM markets in 2012 have covered over 100 percent of their total costs on a cumulative basis in the BGE Zone and PSEG Zone and 62 percent of total costs in the COMED Zone. Energy market revenues alone were not sufficient to cover total costs in any scenario, which demonstrates the critical role of the capacity market revenue in covering total costs. Covering 100 percent of total costs in this analysis includes earning the assumed rate of return. Units earned a positive rate of return even when covering less than 100 percent of the identified costs.

Under cost of service regulation, units are guaranteed that they will cover their total costs, assuming that the costs were determined to be reasonable. To the extent that units built in the PJM markets did not cover their total costs, investors were worse off and customers were better off than under cost of service regulation, ignoring the benefits of competition on reducing costs and improving technology and ignoring the possibility of over earning under cost of service regulation.

Figure 7-5 compares cumulative energy market net revenues and energy market net revenues plus capacity market revenues to cumulative levelized costs for a new entrant CC that began operation on January 1, 2007, and a new entrant CC that began operation on January 1, 2012. The solid black line shows the total net revenue required to cover total costs. The solid colored lines show net energy revenue by zone. The dashed colored lines show the sum of net energy and capacity revenue by zone.

23 Net revenues are calculated for zones in which there are sufficient operating units to determine capacity factor for a new entrant unit.

Figure 7-5 Historical new entrant CC revenue adequacy: 2007 through March 2023 and 2012 through March 2023[24]

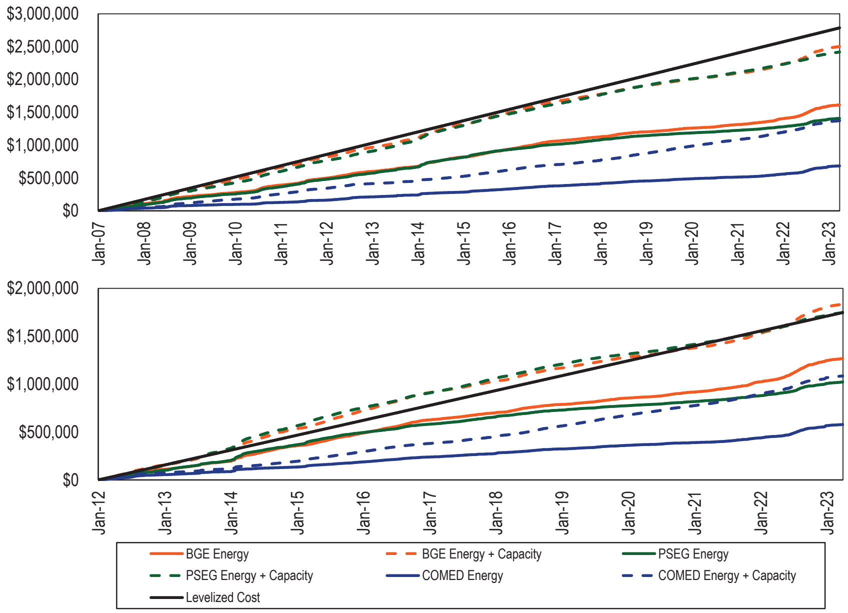


Table 7-13 shows the percent of levelized total costs recovered.

Table 7-13 Percent of levelized total costs recovered

	2007 CC	2012 CC
BGE	90%	105%
COMED	49%	62%
PSEG	87%	100%

24 The gas pipeline pricing points used in this analysis are Zone 6 non-NY for BGE, Chicago City Gate for COMED, and Texas Eastern M3 for PSEG.

The assumptions used for this analysis are shown in Table 7-14.

Table 7-14 Assumptions for analysis of new entry in 2007 and 2012

	2007 CC	2012 CC
Project Cost	$658,598,000	$665,995,000
Fixed O&M ($/MW-Year)	$20,016	$20,126
End of Life Value	$0	$0
Loan Term	20 years	20 years
Percent Equity (%)	50%	50%
Percent Debt (%)	50%	50%
Loan Interest Rate (%)	7%	7%
Cost of Equity (%)	12.0%	12.0%
Federal Income Tax Rate (%)	35%	35%
State Income Tax Rate (%)	9%	9%
General Escalation (%)	2.5%	2.5%
Technology	GE Frame 7FA.04	GE Frame 7FA.05
ICAP (MW)	601	655
Depreciation MACRS 150% declining balance	20 years	20 years
IRR (%)	12.0%	12.0%

Nuclear Net Revenue Analysis

The analysis of nuclear plants includes annual avoidable costs and incremental capital expenditures from the Nuclear Energy Institute (NEI) based on NEI's calculations of average costs for all U.S. nuclear plants.[25] [26] The analysis includes the most recent operating cost data and incremental capital expenditure data for single unit plants and multi unit plants published by NEI, for 2021.[27] This is likely to result in conservatively high costs for the forward looking analysis. NEI average operating costs have decreased since their peak in 2012 (a 13.7 percent decrease from 2012 through 2021 for all plants including single and multiple unit plants).[28] NEI average incremental capital expenditures have decreased since their peak in 2012 (a 47.6 percent decrease from 2012 through 2021 for all plants including single and multiple unit

25 Operating costs from: Nuclear Energy Institute (October 2022). "Nuclear Costs in Context," <https://www.nei.org/CorporateSite/media/filefolder/resources/reports-and-briefs/2022-Nuclear-Costs-in-Context.pdf>. Individual plants may vary from the average due to factors such as geographic location, local labor costs, the timing of refueling outages and other unit specific factors. This is the most current NEI data available.
26 The NEI costs for Hope Creek were treated as that of a two unit configuration because the unit is located in the same area as Salem 1 & 2. The net surplus of Hope Creek is sensitive to the accuracy of this assumption.
27 NEI also provides average costs by plant run by operators with one plant or multiple plants, by market, and by type of nuclear reactor. Plants run by operators with multiple plants have lower average costs than plants run by operators with a single plant. Plants participating in wholesale markets have lower average costs than plants in regulated markets. PWR reactors have lower average generating costs than BWR reactors.
28 Operating costs in this paragraph are operating costs as specified by NEI and do not include fuel costs or capital expenditures. Operating costs for single unit plants decreased by $1.55/MWh, or 5.9 percent, from 2020 to 2021. Operating costs for multiple unit plants increased by $0.07/MWh, or 0.4 percent, from 2020 to 2021.

plants).[29] NEI's incremental capital expenditures peaked in 2012 as a result of regulatory requirements following the 2011 accident at the Fukushima nuclear plant in Japan.

The results for nuclear plants are sensitive to small changes in PJM energy and capacity prices, both actual and forward prices.[30] When gas prices are high and LMPs are high as a result, net revenues to nuclear plants increase. In 2014, the polar vortex resulted in a significant increase in net revenues to nuclear plants. When gas prices are low and LMPs are low as a result, net revenues to nuclear plants decrease. In 2016, PJM energy prices were then at the lowest level since the introduction of competitive markets on April 1, 1999, and remained low in 2017. As a result, in 2016 and 2017, a significant proportion of nuclear plants did not cover annual avoidable costs based on current year prices.[31] In 2018, high gas prices and high LMPs resulted in a significant increase in net revenues for nuclear plants in PJM. Energy prices in 2018 were significantly higher than in 2017. Although energy prices in 2019 were lower than in 2016, higher capacity market revenues more than offset the difference. In 2020, PJM energy prices were at the lowest level since the introduction of competitive markets, even lower than in 2016. Average energy prices in 2022 were higher than energy prices in any year since the inception of PJM markets in 1999. Based on forward prices as of April 3, 2023, nuclear plant energy revenues for 2023 are similar to 2021 actual energy revenues, and nuclear plant energy revenues for 2024 and 2025 are higher than actual revenues in all years since 2014, with the exception of 2022. The actual net revenue results for individual nuclear plants are a function of the degree to which actual unit costs are less than or greater than the benchmark NEI data.

Table 7-15 shows energy market prices, Table 7-16 and Table 7-17 show capacity market prices and Table 7-18 shows nuclear cost data for the 16 nuclear plants in PJM in addition to Oyster Creek, which retired September 17, 2018, and Three Mile Island, which retired September 20, 2019.[32] The analysis excludes the Catawba 1 nuclear unit. Partial data is provided for the Cook, North Anna, and Surry nuclear units. The AEP Cook nuclear units are designated FRR. North Anna 1 and 2 and Surry 1 and 2 are part of the Dominion FRR for the 2022/2023 Delivery Year. FRR units receive cost of service revenues and are not subject to PJM market revenues.[33] Duke's Catawba 1 is not in PJM but is pseudo tied to PJM.

For nuclear plants, all calculations are based on publicly available data in order to avoid revealing confidential information. Historical nuclear unit revenue is based on day-ahead LMP at the relevant node. Nuclear unit capacity revenue assumes that the unit cleared its full unforced capacity at the BRA locational clearing price. Unforced capacity is determined using the annual class average EFORd rate.

29 Capital expenditures have decreased 46.8 percent since 2012 for single unit plants and 46.7 percent for multiple unit plants.
30 A change in the capacity market price of $24 per MW-day translates into a change in capacity revenue of $1.00 per MWh for a nuclear power plant operating at a capacity factor of 100 percent. A change in the capacity market price of $24 per MW-day translates into a change in capacity revenue of $1.06 per MWh for a nuclear power plant operating at a capacity factor of 0.946 percent.
31 The MMU submitted testimony in New Jersey on the same issues of nuclear economics. *Establishing Nuclear Diversity Certificate Program*. Bill No. S-877 New Jersey Senate Environment and Energy Committee. (2018). *Revised Statement of Joseph Bowring*.
32 Installed capacity is from NEI, "Map of U.S. Nuclear Plants," <https://www.nei.org/resources/map-of-us-nuclear-plants>.
33 See "Resources Designated in 2022/2023 FRR Capacity Plans as of April 23, 2021," <https://www.pjm.com/-/media/markets-ops/rpm/rpm-auction-info/2022-2023/2022-2023-resources-designated-in-frr-plans.ashx>.

Table 7-15 Nuclear unit day-ahead LMP: 2008 through 2022

	ICAP	Average DA LMP ($/MWh)														
	(MW)	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Beaver Valley	1,808	$49.46	$31.51	$35.59	$37.43	$30.34	$34.24	$41.86	$30.35	$27.07	$29.11	$36.35	$26.22	$20.33	$37.07	$68.26
Braidwood	2,337	$48.10	$27.76	$31.48	$32.02	$27.51	$30.26	$37.34	$25.97	$24.30	$24.99	$27.11	$22.88	$18.23	$33.74	$60.85
Byron	2,300	$47.61	$23.98	$28.49	$28.09	$24.25	$29.22	$35.05	$21.00	$17.94	$23.79	$26.96	$22.19	$17.66	$32.81	$60.48
Calvert Cliffs	1,726	$78.63	$41.05	$51.27	$46.53	$35.19	$40.27	$57.88	$40.30	$32.64	$31.57	$38.79	$28.00	$21.88	$41.24	$79.61
Cook	2,177	$52.26	$32.20	$36.52	$37.41	$30.09	$34.14	$40.49	$29.94	$26.93	$28.03	$31.44	$25.07	$19.59	$34.81	$65.75
Davis Besse	894	-	-	-	$39.68	$31.68	$36.10	$47.21	$31.94	$27.80	$28.85	$34.44	$26.33	$20.54	$37.34	$69.34
Dresden	1,797	$48.76	$28.27	$32.73	$33.07	$28.42	$31.82	$39.22	$27.45	$25.89	$26.35	$28.25	$23.41	$18.73	$34.32	$62.01
Hope Creek	1,172	$73.34	$39.43	$48.03	$45.52	$33.07	$37.43	$51.99	$32.41	$23.20	$26.78	$32.93	$22.45	$17.32	$30.16	$61.81
LaSalle	2,265	$47.96	$27.71	$31.53	$31.93	$27.56	$30.94	$37.88	$26.28	$23.95	$24.71	$27.19	$22.75	$18.14	$33.54	$60.59
Limerick	2,242	$73.49	$39.49	$48.23	$45.27	$33.09	$37.28	$51.71	$32.65	$23.37	$26.99	$33.08	$22.68	$17.31	$31.05	$62.64
North Anna	1,892	$75.14	$39.89	$50.59	$45.47	$33.87	$38.55	$53.37	$38.05	$30.50	$31.27	$38.44	$27.39	$21.06	$39.99	$77.48
Oyster Creek	608	$75.49	$40.43	$49.29	$46.74	$33.69	$38.62	$52.85	$33.10	$23.79	$27.52	NA	NA	NA	NA	NA
Peach Bottom	2,550	$73.09	$39.32	$47.70	$44.73	$32.81	$37.37	$51.52	$31.98	$23.07	$26.76	$32.63	$21.58	$16.93	$30.77	$62.45
Perry	1,240	-	-	$36.99	$38.76	$31.68	$36.69	$46.14	$32.77	$27.84	$29.91	$37.24	$26.76	$20.49	$37.76	$69.95
Quad Cities	1,819	$47.28	$24.81	$27.53	$26.79	$20.43	$25.94	$30.71	$19.47	$18.04	$23.09	$25.54	$21.13	$15.95	$31.39	$60.69
Salem	2,285	$73.41	$39.51	$48.02	$45.50	$33.06	$37.40	$51.96	$32.37	$23.18	$26.76	$32.90	$22.43	$17.32	$30.12	$61.76
Surry	1,676	$71.96	$39.02	$49.30	$45.01	$33.62	$37.98	$51.75	$37.91	$30.08	$31.08	$38.50	$26.65	$20.41	$39.30	$75.02
Susquehanna	2,494	$69.96	$38.24	$45.95	$44.78	$32.10	$36.76	$50.93	$32.47	$23.66	$27.14	$32.42	$21.08	$16.03	$30.36	$60.54
Three Mile Island	803	$72.46	$39.11	$46.72	$44.15	$32.43	$36.83	$50.47	$30.94	$22.96	$27.12	$31.76	NA	NA	NA	NA

Table 7-16 BRA capacity market clearing prices ($/MW-Day): 2007/2008 through 2024/2025[34 35]

	ICAP	BRA Capacity Price ($/MW-Day)																	
	(MW)	07/08	08/09	09/10	10/11	11/12	12/13	13/14	14/15	15/16	16/17	17/18	18/19	19/20	20/21	21/22	22/23	23/24	24/25
Beaver Valley	1,808	$41	$112	$102	$174	$110	$16	$28	$126	$136	$59	$120	$165	$100	$77	$140	$50	$34	$29
Braidwood	2,337	$41	$112	$102	$174	$110	$16	$28	$126	$136	$59	$120	$215	$203	$188	$196	$69	$34	$29
Byron	2,300	$41	$112	$102	$174	$110	$16	$28	$126	$136	$59	$120	$215	$203	$188	$196	$69	$34	$29
Calvert Cliffs	1,726	$189	$210	$237	$174	$110	$133	$226	$137	$167	$119	$120	$165	$100	$86	$140	$96	$49	$49
Cook	2,177	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Davis Besse	894	-	-	-	-	$109	$20	$28	$126	$357	$114	$120	$165	$100	$77	$171	$50	$34	$29
Dresden	1,797	$41	$112	$102	$174	$110	$16	$28	$126	$136	$59	$120	$215	$203	$188	$196	$69	$34	$29
Hope Creek	1,172	$198	$149	$191	$174	$110	$140	$245	$137	$167	$119	$120	$225	$120	$188	$166	$98	$49	$55
LaSalle	2,265	$41	$112	$102	$174	$110	$16	$28	$126	$136	$59	$120	$215	$203	$188	$196	$69	$34	$29
Limerick	2,242	$198	$149	$191	$174	$110	$140	$245	$137	$167	$119	$120	$225	$120	$188	$166	$98	$49	$55
North Anna	1,892	$41	$112	$102	$174	$110	$16	$28	$126	$136	$59	$120	$165	$100	$77	$140	NA	NA	NA
Oyster Creek	608	$198	$149	$191	$174	$110	$140	$245	$137	$167	$119	$120	$225	$120	$188	-	-	-	-
Peach Bottom	2,550	$198	$149	$191	$174	$110	$140	$245	$137	$167	$119	$120	$225	$120	$188	$166	$98	$49	$55
Perry	1,240	-	-	-	-	$109	$20	$28	$126	$357	$114	$120	$165	$100	$77	$171	$50	$34	$29
Quad Cities	1,819	$41	$112	$102	$174	$110	$16	$28	$126	$136	$59	$120	$215	$203	$188	$196	$69	$34	$29
Salem	2,285	$198	$149	$191	$174	$110	$140	$245	$137	$167	$119	$120	$225	$120	$188	$166	$98	$49	$55
Surry	1,676	$41	$112	$102	$174	$110	$16	$28	$126	$136	$59	$120	$165	$100	$77	$140	NA	NA	NA
Susquehanna	2,494	$41	$112	$191	$174	$110	$133	$226	$137	$167	$119	$120	$165	$100	$86	$140	$96	$49	$49
Three Mile Island	803	$41	$112	$191	$174	$110	$133	$226	$137	$167	$119	$120	$165	$100	$86	$140	-	-	-

34 Oyster Creek retired September 17, 2018. Exelon. "Oyster Creek Generating Station Retires from Service," (September 17, 2018) <http://www.exeloncorp.com/newsroom/oyster-creek-retires>. Three Mile Island retired September 20, 2019. Exelon. "Three Mile Island Generating Station Unit 1 Retires from Service After 45 Years," (September 20, 2019) <https://www.exeloncorp.com/newsroom/three-mile-island-generating-station-unit-1-retires>. For the 2022/2023 Delivery Year, Surry is part of Dominion FRR.

35 Cook is designated FRR. North Anna and Surry are in Dominion FRR beginning with the 2022/2023 Delivery Year.

Table 7-17 Nuclear unit capacity market revenue ($/MWh): 2008 through 2024[36 37]

	ICAP	Capacity Revenue ($/MWh)																
	(MW)	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Beaver Valley	1,808	$3.57	$4.50	$6.23	$5.87	$2.41	$1.01	$3.70	$5.75	$3.96	$4.17	$6.42	$5.61	$3.81	$4.93	$3.80	$1.77	$1.35
Braidwood	2,337	$3.57	$4.50	$6.23	$5.87	$2.41	$1.01	$3.70	$5.75	$3.96	$4.17	$7.71	$9.20	$8.58	$8.35	$5.28	$2.11	$1.35
Byron	2,300	$3.57	$4.50	$6.23	$5.87	$2.41	$1.01	$3.70	$5.75	$3.96	$4.17	$7.71	$9.20	$8.58	$8.35	$5.28	$2.11	$1.35
Calvert Cliffs	1,726	$8.73	$9.59	$8.64	$5.87	$5.38	$8.21	$7.53	$6.74	$6.04	$5.26	$6.42	$5.62	$4.07	$5.10	$4.97	$2.99	$2.15
Cook	2,177	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Davis Besse	894	NA	NA	NA	NA	$2.49	$1.08	$3.70	$11.40	$9.33	$5.17	$6.42	$5.61	$3.81	$5.73	$4.36	$1.77	$1.35
Dresden	1,797	$3.57	$4.50	$6.23	$5.87	$2.41	$1.01	$3.70	$5.75	$3.96	$4.17	$7.71	$9.20	$8.58	$8.35	$5.28	$2.11	$1.35
Hope Creek	1,172	$7.33	$7.37	$7.82	$5.87	$5.54	$8.81	$7.87	$6.74	$6.04	$5.26	$7.98	$7.24	$7.05	$7.59	$5.48	$3.03	$2.29
LaSalle	2,265	$3.57	$4.50	$6.23	$5.87	$2.41	$1.01	$3.70	$5.75	$3.96	$4.17	$7.71	$9.20	$8.58	$8.35	$5.28	$2.11	$1.35
Limerick	2,242	$7.33	$7.37	$7.82	$5.87	$5.54	$8.81	$7.87	$6.74	$6.04	$5.26	$7.98	$7.24	$7.05	$7.59	$5.48	$3.03	$2.29
North Anna	1,892	$3.57	$4.50	$6.23	$5.87	$2.41	$1.01	$3.70	$5.75	$3.96	$4.17	$6.42	$5.61	$3.81	$4.93	NA	NA	NA
Oyster Creek	608	$7.33	$7.37	$7.82	$5.87	$5.54	$8.81	$7.87	$6.74	$6.04	$5.26	-	-	-	-	-	-	-
Peach Bottom	2,550	$7.33	$7.37	$7.82	$5.87	$5.54	$8.81	$7.87	$6.74	$6.04	$5.26	$7.98	$7.24	$7.05	$7.59	$5.48	$3.03	$2.29
Perry	1,240	NA	NA	NA	NA	$2.49	$1.08	$3.70	$11.40	$9.33	$5.17	$6.42	$5.61	$3.81	$5.73	$4.36	$1.77	$1.35
Quad Cities	1,819	$3.57	$4.50	$6.23	$5.87	$2.41	$1.01	$3.70	$5.75	$3.96	$4.17	$7.71	$9.20	$8.58	$8.35	$5.28	$2.11	$1.35
Salem	2,285	$7.33	$7.37	$7.82	$5.87	$5.54	$8.81	$7.87	$6.74	$6.04	$5.26	$7.98	$7.24	$7.05	$7.59	$5.48	$3.03	$2.29
Surry	1,676	$3.57	$4.50	$6.23	$5.87	$2.41	$1.01	$3.70	$5.75	$3.96	$4.17	$6.42	$5.61	$3.81	$4.93	NA	NA	NA
Susquehanna	2,494	$3.57	$6.72	$7.82	$5.87	$5.38	$8.21	$7.53	$6.74	$6.04	$5.26	$6.42	$5.61	$4.06	$5.10	$4.97	$2.99	$2.15
Three Mile Island	803	$3.57	$6.72	$7.82	$5.87	$5.38	$8.21	$7.53	$6.74	$6.04	$5.26	$6.42	-	-	-	-	-	-

36 Capacity revenue calculated by adjusting the BRA Capacity Price for calendar year, by the class average EFORd, and by the annual class average capacity factor. Class average EFORd and capacity factor is from *2022 State of the Market Report for PJM*, Volume 2, Section 5: Capacity Market.

37 Oyster Creek retired September 17, 2018. Exelon. "Oyster Creek Generating Station Retires from Service," (September 17, 2018) <http://www.exeloncorp.com/newsroom/oyster-creek-retires>. Three Mile Island retired September 20, 2019. Exelon. "Three Mile Island Generating Station Unit 1 Retires from Service After 45 Years," (September 20, 2019) <https://www.exeloncorp.com/newsroom/three-mile-island-generating-station-unit-1-retires>.

Table 7-18 Nuclear unit costs: 2008 through 2021[38] [39]

	ICAP	NEI Costs ($/MWh)													
	(MW)	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Beaver Valley	1,808	$26.73	$29.76	$31.34	$34.51	$36.06	$33.84	$33.84	$32.90	$31.63	$30.89	$29.07	$28.38	$27.03	$27.18
Braidwood	2,337	$26.73	$29.76	$31.34	$34.51	$36.06	$33.84	$33.84	$32.90	$31.63	$30.89	$29.07	$28.38	$27.03	$27.18
Byron	2,300	$26.73	$29.76	$31.34	$34.51	$36.06	$33.84	$33.84	$32.90	$31.63	$30.89	$29.07	$28.38	$27.03	$27.18
Calvert Cliffs	1,726	$26.73	$29.76	$31.34	$34.51	$36.06	$33.84	$33.84	$32.90	$31.63	$30.89	$29.07	$28.38	$27.03	$27.18
Cook	2,177	$26.73	$29.76	$31.34	$34.51	$36.06	$33.84	$33.84	$32.90	$31.63	$30.89	$29.07	$28.38	$27.03	$27.18
Davis Besse	894	$35.31	$39.36	$41.23	$45.45	$47.41	$44.16	$44.32	$44.51	$41.39	$42.66	$42.00	$38.40	$39.64	$37.42
Dresden	1,797	$26.73	$29.76	$31.34	$34.51	$36.06	$33.84	$33.84	$32.90	$31.63	$30.89	$29.07	$28.38	$27.03	$27.18
Hope Creek	1,172	$26.73	$29.76	$31.34	$34.51	$36.06	$33.84	$33.84	$32.90	$31.63	$30.89	$29.07	$28.38	$27.03	$27.18
LaSalle	2,265	$26.73	$29.76	$31.34	$34.51	$36.06	$33.84	$33.84	$32.90	$31.63	$30.89	$29.07	$28.38	$27.03	$27.18
Limerick	2,242	$26.73	$29.76	$31.34	$34.51	$36.06	$33.84	$33.84	$32.90	$31.63	$30.89	$29.07	$28.38	$27.03	$27.18
North Anna	1,892	$26.73	$29.76	$31.34	$34.51	$36.06	$33.84	$33.84	$32.90	$31.63	$30.89	$29.07	$28.38	$27.03	$27.18
Oyster Creek	608	$35.31	$39.36	$41.23	$45.45	$47.41	$44.16	$44.32	$44.51	$41.39	$42.66	-	-	-	-
Peach Bottom	2,550	$26.73	$29.76	$31.34	$34.51	$36.06	$33.84	$33.84	$32.90	$31.63	$30.89	$29.07	$28.38	$27.03	$27.18
Perry	1,240	$35.31	$39.36	$41.23	$45.45	$47.41	$44.16	$44.32	$44.51	$41.39	$42.66	$42.00	$38.40	$39.64	$37.42
Quad Cities	1,819	$26.73	$29.76	$31.34	$34.51	$36.06	$33.84	$33.84	$32.90	$31.63	$30.89	$29.07	$28.38	$27.03	$27.18
Salem	2,285	$26.73	$29.76	$31.34	$34.51	$36.06	$33.84	$33.84	$32.90	$31.63	$30.89	$29.07	$28.38	$27.03	$27.18
Surry	1,676	$26.73	$29.76	$31.34	$34.51	$36.06	$33.84	$33.84	$32.90	$31.63	$30.89	$29.07	$28.38	$27.03	$27.18
Susquehanna	2,494	$26.73	$29.76	$31.34	$34.51	$36.06	$33.84	$33.84	$32.90	$31.63	$30.89	$29.07	$28.38	$27.03	$27.18
Three Mile Island	803	$35.31	$39.36	$41.23	$45.45	$47.41	$44.16	$44.32	$44.51	$41.39	$42.66	$42.00	-	-	-

In 2020, no nuclear plants covered their fuel costs, operating costs, and incremental capital expenditures as a result of lower energy prices. In 2021 and 2022, all nuclear plants covered their fuel costs, operating costs, and incremental capital expenditures as a result of higher energy prices.

Table 7-19 shows the surplus or shortfall in $/MWh for the 16 nuclear plants in PJM, and Oyster Creek and Three Mile Island, calculated using historic LMP and cost data. In 2021 and 2022, all nuclear plants more than covered their fuel costs, operating costs, and capital expenditures as a result of higher energy prices. The surplus or shortfall assumes that the unit cleared its full unforced capacity at the BRA locational clearing price.[40] Unforced capacity is determined using the annual class average EFORd rate.

The market revenues are based in part on the sale of capacity. Some nuclear plants did not clear the capacity market as a result of decisions by plant owners about how to offer the plants in the capacity market auctions. When nuclear plants do not clear in the capacity market, it is a result of the offer behavior of the plants and does not reflect the economic viability of the plants unless the plants offer accurate net avoidable costs and fail to clear. This analysis is intended to define whether the plants are receiving a retirement signal from the PJM markets. If the plants are viable including both energy and capacity market revenues based on actual clearing prices, then the PJM markets indicate that the plant is economically viable. If plant owners decide to offer so as to not clear in the capacity market, that does not change the market signals to the plants. Such decisions may reflect a variety of considerations. Quad Cities and a portion of Byron's capacity did not clear in the 2019/2020 Auction.[41] Quad Cities did not clear in the 2020/2021 Auction.[42] Dresden and most of Byron did not clear in

38 Operating costs from: Nuclear Energy Institute (October, 2022). "Nuclear Costs in Context," <https://www.nei.org/CorporateSite/media/filefolder/resources/reports-and-briefs/2022-Nuclear-Costs-in-Context.pdf>.
39 Oyster Creek retired on September 17, 2018. Exelon. "Oyster Creek Generating Station Retires from Service," (September 17, 2018) <http://www.exeloncorp.com/newsroom/oyster-creek-retires>. Three Mile Island retired September 20, 2019. Exelon. "Three Mile Island Generating Station Unit 1 Retires from Service After 45 Years," (September 20, 2019) <https://www.exeloncorp.com/newsroom/three-mile-island-generating-station-unit-1-retires>.
40 Installed capacity is from NEI. "Maps of U.S. Nuclear Plants," <https://www.nei.org/resources/map-of-us-nuclear-plants>.
41 Exelon. "Exelon Announces Outcome of 2019-2020 PJM Capacity Auction," (May 25, 2016) <http://www.exeloncorp.com/newsroom/pjm-auction-results-2016>.
42 Exelon, "Exelon Announces Outcome of 2020-2021 PJM Capacity Auction," (May 24, 2017) <http://www.exeloncorp.com/newsroom/pjm-auction-results-release-2017>.

the 2021/2022 Auction.[43] Beaver Valley, Davis Besse, and Perry did not clear in the 2021/2022 Auction.[44] Byron, Dresden, and Quad Cities did not clear in the 2022/2023 Auction.[45]

Nuclear unit revenue is a combination of energy market revenue, ancillary market revenue and capacity market revenue. Negative energy market prices do not have a significant impact on nuclear unit revenue. Since 2014, negative energy market prices have affected nuclear plants' annual total revenues by an average of 0.1 percent. Negative LMPs reduced nuclear plant total revenues by an average of 0.0 percent and a maximum of 0.6 percent in 2014, an average of 0.2 percent and a maximum of 1.2 percent in 2015, an average of 0.1 percent and a maximum of 0.7 percent in 2016, an average of 0.0 percent and a maximum of 0.6 percent in 2017, an average of 0.0 percent and a maximum of 0.0 percent in 2018, an average of 0.0 percent and a maximum of 0.2 percent in 2019, an average of 0.1 percent and a maximum of 1.7 percent in 2020, an average of 0.0 percent and a maximum of 0.3 percent in 2021, and an average of 0.0 percent and a maximum of 0.0 percent in 2022.[46]

In 2022, all nuclear plants covered their fuel costs, operating costs, and incremental capital expenditures as a result of higher energy prices.

Table 7-19 Nuclear unit surplus (shortfall) based on public data: 2008 through 2022

	ICAP	Surplus (Shortfall) ($/MWh)														
	(MW)	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Beaver Valley	1,808	$26.3	$6.3	$10.5	$8.8	($3.3)	$1.4	$11.7	$3.2	($0.4)	$2.6	$13.9	$3.7	($2.7)	$15.0	$45.1
Braidwood	2,337	$24.9	$2.5	$6.4	$3.4	($6.1)	($2.6)	$7.2	($1.2)	($3.2)	($1.6)	$5.9	$3.9	($0.0)	$15.1	$39.1
Byron	2,300	$24.5	($1.3)	$3.4	($0.6)	($9.4)	($3.6)	$4.9	($6.1)	($9.6)	($2.8)	$5.8	$3.2	($0.6)	$14.1	$38.7
Calvert Cliffs	1,726	$60.6	$20.9	$28.6	$17.9	$4.5	$14.6	$31.6	$14.1	$7.2	$6.1	$16.3	$5.4	($0.9)	$19.4	$57.6
Cook	2,177	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Davis Besse	894	NA	NA	NA	NA	($13.2)	($7.0)	$6.6	($1.2)	($4.0)	($8.4)	($0.9)	($6.3)	($15.1)	$5.9	$36.5
Dresden	1,797	$25.6	$3.0	$7.6	$4.4	($5.2)	($1.0)	$9.1	$0.3	($1.5)	($0.1)	$7.1	$4.5	$0.5	$15.7	$40.3
Hope Creek	1,172	$54.0	$17.0	$24.5	$16.9	$2.6	$12.4	$26.0	$6.3	($1.9)	$1.6	$12.3	$1.8	($2.2)	$11.0	$40.6
LaSalle	2,265	$24.8	$2.5	$6.4	$3.3	($6.1)	($1.9)	$7.7	($0.9)	($3.6)	($1.9)	$6.0	$3.7	($0.2)	$14.8	$38.8
Limerick	2,242	$54.1	$17.1	$24.7	$16.6	$2.6	$12.2	$25.7	$6.5	($2.1)	$1.5	$12.1	$1.6	($2.6)	$11.6	$41.0
North Anna	1,892	$52.0	$14.6	$25.5	$16.8	$0.2	$5.7	$23.2	$10.9	$3.0	$4.7	$16.0	$4.8	($2.0)	$17.9	NA
Oyster Creek	608	$47.5	$8.4	$15.9	$7.2	($8.2)	$3.3	$16.4	($4.7)	($11.6)	($9.9)	NA	NA	NA	NA	NA
Peach Bottom	2,550	$53.7	$16.9	$24.2	$16.1	$2.3	$12.3	$25.5	$5.8	($2.2)	$1.4	$11.9	$0.7	($2.7)	$11.5	$41.1
Perry	1,240	NA	NA	NA	NA	($13.2)	($6.4)	$5.5	($0.3)	($4.0)	($7.4)	$1.9	($5.8)	($15.1)	$6.3	$37.1
Quad Cities	1,819	$24.1	($0.4)	$2.4	($1.8)	($13.2)	($6.9)	$0.6	($7.7)	($9.5)	($3.5)	$4.3	$2.1	($2.4)	$12.7	$38.9
Salem	2,285	$54.0	$17.1	$24.5	$16.9	$2.6	$12.4	$26.0	$6.2	($2.1)	$1.5	$12.2	$1.6	($2.3)	$10.9	$40.4
Surry	1,676	$48.8	$13.8	$24.2	$16.4	($0.0)	$5.1	$21.6	$10.8	$2.6	$4.5	$16.0	$4.1	($2.6)	$17.2	NA
Susquehanna	2,494	$46.8	$15.2	$22.4	$16.1	$1.4	$11.1	$24.6	$6.3	($1.6)	$1.8	$10.1	($1.4)	($6.6)	$8.6	$38.6
Three Mile Island	803	$40.7	$6.5	$13.3	$4.6	($9.6)	$0.9	$13.7	($6.8)	($12.4)	($10.3)	($3.8)	NA	NA	NA	NA

43 Exelon, "Exelon Announces Outcome of 2021-2022 PJM Capacity Auction," (May 24, 2018) <http://www.exeloncorp.com/newsroom/exelon-announces-outcome-of-2021-2022-pjm-capacity-auction>.
44 PRNewswire. "FirstEnergy Solutions Comments on Results of PJM Capacity Auction," (May 24, 2018) <https://www.prnewswire.com/news-releases/firstenergy-solutions-comments-on-results-of-pjm-capacity-auction-300654549.html>.
45 NuclearNewswire. "Byron, Dresden, Quad Cities Fail to Clear in PJM Capacity Auction," (June 8, 2021) <https://www.ans.org/news/article-2967/byron-dresden-quad-cities-fail-to-clear-in-pjm-capacity-auction/>.
46 Analysis is based on actual unit generation and received energy market and capacity market revenues. Negative prices in the DA and RT market were set to zero for comparison. Results round to 0.0 percent.

In order to evaluate the expected viability of nuclear plants, analysis was performed based on forward energy market prices for 2023, 2024, and 2025 and known capacity market prices for 2023 and 2024. The purpose of the forward analysis is to evaluate whether current forward prices are consistent with nuclear plants covering their annual avoidable costs over the next three years. While the forward capacity market prices are known through the 2024/2025 Delivery Year, actual energy prices will vary from forward values. Nuclear plants may choose to sell their output at a range of forward prices and for a range of future years.

Table 7-20 shows PJM energy prices (LMP), annual fuel, and operating and capital expenditures used for the analysis of the period 2023 through 2025. Capacity revenues are not presented for calendar year 2025 because the 2025/2026 BRA has not yet been run. The LMPs are based on forward prices with a basis adjustment for the specific plant locations.[47] Forward prices are as of April 3, 2023. The capacity prices are known based on PJM capacity auction results.

Table 7-20 Forward prices in PJM energy markets, capacity revenue, and annual costs

	ICAP (MW)	Average Forward LMP ($/MWh)			Ancillary Revenue ($/MWh)	Capacity Revenue ($/MWh)		2021 NEI Costs ($/MWh)		
		2023	2024	2025	Reactive	2023	2024	Fuel	Operating	Capital
Beaver Valley	1,808	$34.73	$44.21	$47.41	$0.21	$1.77	$1.35	$5.57	$16.50	$5.11
Braidwood	2,337	$30.34	$38.30	$41.08	$0.18	$2.11	$1.35	$5.57	$16.50	$5.11
Byron	2,300	$29.78	$37.49	$40.21	$0.15	$2.11	$1.35	$5.57	$16.50	$5.11
Calvert Cliffs	1,726	$38.87	$49.99	$53.56	$0.19	$2.99	$2.15	$5.57	$16.50	$5.11
Cook	2,177	$32.84	$41.90	$44.95	$0.13	NA	NA	$5.57	$16.50	$5.11
Davis Besse	894	$34.38	$43.96	$47.13	$0.21	$1.77	$1.35	$5.45	$24.78	$7.19
Dresden	1,797	$31.01	$39.05	$41.89	$0.23	$2.11	$1.35	$5.57	$16.50	$5.11
Hope Creek	1,172	$30.75	$41.86	$44.74	$0.47	$3.03	$2.29	$5.57	$16.50	$5.11
LaSalle	2,265	$30.17	$38.14	$40.91	$0.13	$2.11	$1.35	$5.57	$16.50	$5.11
Limerick	2,242	$30.87	$42.31	$45.21	$0.10	$3.03	$2.29	$5.57	$16.50	$5.11
North Anna	1,892	$38.91	$50.14	$53.72	$0.18	NA	NA	$5.57	$16.50	$5.11
Peach Bottom	2,550	$30.90	$41.29	$44.15	$0.31	$3.03	$2.29	$5.57	$16.50	$5.11
Perry	1,240	$35.52	$45.22	$48.48	$0.21	$1.77	$1.35	$5.45	$24.78	$7.19
Quad Cities	1,819	$29.86	$37.39	$40.09	$0.13	$2.11	$1.35	$5.57	$16.50	$5.11
Salem	2,285	$30.72	$41.83	$44.71	$0.35	$3.03	$2.29	$5.57	$16.50	$5.11
Surry	1,676	$37.97	$48.94	$52.43	$0.16	NA	NA	$5.57	$16.50	$5.11
Susquehanna	2,494	$31.00	$40.19	$43.04	$0.32	$2.99	$2.15	$5.57	$16.50	$5.11

The MMU also calculates the capacity price that would be required to cover the net avoidable costs for each nuclear plant.

Based on the FERC order allowing the inclusion of major maintenance in energy offers, major maintenance costs can no longer be included in gross ACR values.[48] The MMU calculates the capacity price that would be required to cover the net avoidable costs for each nuclear plant with major maintenance included in avoidable costs and with major maintenance excluded from avoidable costs. For the case including major maintenance, gross ACR is NEI total cost including fuel, operating cost, and incremental capital expenditures. For the case excluding major maintenance, gross ACR is NEI total cost including fuel and operating cost, excluding capital expenditures as a proxy for fixed VOM, given that NEI does not provide a breakout of major maintenance. NEI incremental capital expenditures are likely to be a conservatively low estimate of major maintenance expense.

47 Forward prices on December 27, 2022. Forward prices are reported for PJM trading hubs which are adjusted to reflect the historical differences between prices at the trading hub and prices at the relevant plant locations. The basis adjustment is based on 2022 data.
48 See 167 FERC ¶ 61,030 at P 41.

All generating plants including nuclear plants must cover their gross avoidable costs, including major maintenance, to remain economically viable. All of the MMU analysis of nuclear plant economics includes gross avoidable costs as reported by NEI unless explicitly stated otherwise.

In Table 7-21, the capacity price required to cover avoidable costs in $/MWh is calculated by taking the total NEI costs in $/MWh and subtracting the total expected energy and ancillary services revenues in $/MWh. Total expected energy revenue is the unit's ICAP multiplied by the average forward LMP multiplied by the class average equivalent availability factor (EAF). Total expected ancillary services revenue is unit specific reactive capability revenue.[49] The capacity price required to cover avoidable costs in $/MW-day is calculated by multiplying the required price in $/MWh by 24. Plants may have actual operating costs higher or lower than the NEI average.

In Table 7-21, for 2023, the capacity price required to cover avoidable costs is $0/MW-day for all units using NEI data as reported including capital expenditures, and is $0/MW-day for all plants, excluding capital expenditures as a proxy for major maintenance.[50] Net revenues based on forward energy prices alone are greater than or equal to avoidable costs in 2023, 2024, and 2025 without any contribution from capacity market revenues for all multiple unit plants. The result is that all net ACR values for multiple unit plants in Table 7-21 are zero. Davis Besse and Perry are both single unit plants and both have a positive net ACR for 2023.

Table 7-21 Net ACR

	ICAP	Net ACR ($/MWh)			Net ACR ($/MW-Day)			Net ACR Excluding Capital ($/MW-Day)		
	(MW)	2023	2024	2025	2023	2024	2025	2023	2024	2025
Beaver Valley	1,808	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Braidwood	2,337	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Byron	2,300	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Calvert Cliffs	1,726	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Cook	2,177	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Davis Besse	894	$2.83	$0.00	$0.00	$64.29	$0.00	$0.00	$0.00	$0.00	$0.00
Dresden	1,797	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Hope Creek	1,172	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
LaSalle	2,265	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Limerick	2,242	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
North Anna	1,892	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Peach Bottom	2,550	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Perry	1,240	$1.69	$0.00	$0.00	$38.45	$0.00	$0.00	$0.00	$0.00	$0.00
Quad Cities	1,819	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Salem	2,285	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Surry	1,676	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Susquehanna	2,494	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00

49 Reactive Supply & Voltage Control Revenue Requirements available from PJM <https://www.pjm.com/markets-and-operations/billing-settlements-and-credit.aspx>.
50 PJM's tariff definition of avoidable costs excludes major maintenance. PJM includes major maintenance costs in the definition of short run marginal costs in energy offers.

Table 7-22 shows the surplus or shortfall that would be received net of avoidable costs and incremental capital expenditures by year, based on forward prices, on a per MWh basis. The fuel and operating costs are the 2021 NEI fuel, operating, and capital costs. Plants may have operating costs higher or lower than the NEI average. Table 7-22 shows the total dollar surplus or shortfall and adjusts energy revenues and operating costs using the annual class average capacity factor.

Changes in forward energy market prices can significantly affect expected profitability of nuclear plants in PJM. The current analysis, based on forward prices for energy and known forward prices for capacity, shows that all nuclear plants are expected to cover their annual avoidable costs in 2023 and 2024 with the exception of Davis Besse in 2023.

Hope Creek, Quad Cities, and Salem all currently receive subsidies. Braidwood, Byron, Dresden, and LaSalle will receive a subsidy if necessary to meet a target net revenue value, in dollar per MWh, from the energy and capacity markets. Based on forward prices as of April 3, 2023, and NEI average costs, none of these three plants with a conditional subsidy need a subsidy, and therefore zero subsidy values are included for these plants in Table 7-22.

Table 7-22 Nuclear unit forward annual surplus (shortfall)[51 52 53 54 55]

	ICAP	Surplus (Shortfall) ($/MWh)		Subsidy ($/MWh)		Surplus (Shortfall) Excluding Subsidy ($ in millions)		Surplus (Shortfall) Including Subsidy ($ in millions)	
	(MW)	2023	2024	2023	2024	2023	2024	2023	2024
Beaver Valley	1,808	$9.53	$18.60			$142.8	$279.4	$142.8	$279.4
Braidwood	2,337	$5.45	$12.65	$0.00	$0.00	$105.5	$245.6	$105.5	$245.6
Byron	2,300	$4.87	$11.81	$0.00	$0.00	$92.8	$225.8	$92.8	$225.8
Calvert Cliffs	1,726	$14.87	$25.15			$212.7	$360.8	$212.7	$360.8
Cook	2,177	NA	NA			NA	NA	NA	NA
Davis Besse	894	($1.06)	$8.11			($7.9)	$60.2	($7.9)	$60.2
Dresden	1,797	$6.17	$13.46	$0.00	$0.00	$91.9	$200.9	$91.9	$200.9
Hope Creek	1,172	$7.06	$17.45	$10.00	$10.00	$68.6	$169.9	$165.7	$267.3
LaSalle	2,265	$5.23	$12.45	$0.00	$0.00	$98.2	$234.2	$98.2	$234.2
Limerick	2,242	$6.82	$17.53			$126.7	$326.6	$126.7	$326.6
North Anna	1,892	NA	NA			NA	NA	NA	NA
Peach Bottom	2,550	$7.06	$16.71			$149.2	$354.1	$149.2	$354.1
Perry	1,240	$0.08	$9.36			$0.8	$96.5	$0.8	$96.5
Quad Cities	1,819	$4.92	$11.69	$16.50	$16.50	$74.2	$176.7	$322.9	$426.1
Salem	2,285	$6.92	$17.30	$10.00	$10.00	$131.0	$328.4	$320.3	$518.3
Surry	1,676	NA	NA			NA	NA	NA	NA
Susquehanna	2,494	$7.13	$15.49			$147.3	$321.0	$147.3	$321.0

51 Report to the General Assembly in Compliance with Section 1-75(d-5) of the Illinois Power Agency Act 20 ILCS 3855/1-75(d-5)(F)(2). Illinois Commerce Commission. August 2019. The report finds that while total ZECs payments are limited by rate impact caps and volume caps, the law's limitation does not unduly constrain the procurement of ZECs.

52 *Application of PSEG Nuclear, LLC for the Zero Emission Certificate Program – Hope Creek, Order Determining the Eligibility of Hope Creek Nuclear Generator to Receive ZECs*, BPU Docket No. ER20080559 (April 27, 2021). *Application of PSEG Nuclear, LLC for the Zero Emission Certificate Program – Salem 1, Order Determining the Eligibility of Salem Unit 1 Nuclear Generator to Receive ZECs, BPU Docket No. ER20080557 (April 27, 201). Application of PSEG Nuclear, LLC for the Zero Emission Certificate Program – Salem 2, Order Determining the Eligibility of Salem Unit 2 Nuclear Generator to Receive ZECs*. BPU Docket No. ER20080557 (April 27, 2021).

53 North Anna and Surry are in Dominion FRR beginning with the 2022/2023 Delivery Year.

54 The subsidy value for Braidwood, Byron, Dresden, and LaSalle is calculated by taking the applicable Baseline Cost less forward energy prices and known capacity prices.

55 The Illinois Energy Transition Act, SB 2408.

Environmental and Renewable Energy Regulations

Environmental requirements and renewable energy mandates have a significant impact on PJM markets. State and federal environmental regulatory requirements affect the economic viability of resources and will result in the retirement of a significant level of capacity resources by 2030. State and federal environmental policies also affect the viability of new resources and the cost of entry. State and federal subsidies for renewable generation have made new solar resources cost competitive with existing coal resources and contributed to the significant level of wind and solar resources entering the market.

Overview

Federal Environmental Regulation

- **MATS.** The U.S. Environmental Protection Agency's (EPA) Mercury and Air Toxics Standards rule (MATS) applies the Clean Air Act (CAA) maximum achievable control technology (MACT) requirement to new or modified sources of emissions of mercury and arsenic, acid gas, nickel, selenium and cyanide.[1] On February 13, 2023, the EPA issued a final rule reaffirming that it remains appropriate and necessary to regulate hazardous air pollutants (HAP), including mercury, from power plants after considering cost.[2] This action revokes a 2020 finding that it was not appropriate and necessary to regulate coal and oil fired power plants under CAA § 112, and would restore the basis for the MATS rule.
- **Air Quality Standards (NO_X and SO_2 Emissions).** The CAA requires each state to attain and maintain compliance with fine particulate matter (PM) and ozone national ambient air quality standards (NAAQS). The CAA also requires that each state prohibit emissions that significantly interfere with the ability of another state to meet NAAQS.[3] On March 15, 2021, the EPA finalized decreases to allowable emissions under the Cross-State Air Pollution Rule (CSAPR) and the 2008 ozone NAAQS for 10 PJM states.[4] On February 28, 2022, the EPA proposed a Federal Implementation Plan (FIP), to be known as the "Transport Rule," for 26 states that addresses the contribution of those states to problems in other states in attaining and maintaining the 2015 Ozone NAAQS.[5] The proposed FIP requirements would establish ozone season NO_X emissions budgets for electric generating units in the PJM states, excluding North Carolina and the District of Columbia. On January 6, 2023, the EPA proposed to lower the primary annual $PM_{2.5}$ standard to 9.0 to 10.0 µg/m^3 from 12.0 µg/m^3.[6]
- **NSR.** On August 1, 2019, the EPA proposed to reform the New Source Review (NSR) permitting program.[7] NSR requires new projects and existing projects receiving major overhauls that significantly increase emissions to obtain permits. Recent EPA proposals would reduce the number of projects that require permits.
- **RICE.** Stationary reciprocating internal combustion engines (RICE) are electrical generation facilities like diesel engines typically used for backup, emergency or supplemental power. RICE must be tested annually.[8] RICE do not have to meet the same emissions standards if they are emergency stationary RICE. Environmental regulations allow emergency stationary RICE participating in demand response programs to operate for up to 100 hours per calendar year when providing emergency demand response when there is a PJM declared NERC Energy Emergency Alert Level 2 or there are five percent voltage/frequency deviations.

  PJM does not prevent emergency stationary RICE that cannot meet its capacity market obligations as a result of EPA emissions standards from participating in PJM markets as DR. Some emergency stationary RICE that cannot meet its capacity market obligations as a result of emissions standards are now included in DR portfolios. Emergency stationary RICE should be prohibited from participation as DR either when registered

1 National Emission Standards for Hazardous Air Pollutants From Coal and Oil-Fired Electric Utility Steam Generating Units and Standards of Performance for Fossil Fuel Fired Electric Utility, Industrial-Commercial-Institutional, and Small Industrial-Commercial-Institutional Steam Generating Units, EPA Docket No. EPA-HQ-OAR-2009-0234, 77 Fed. Reg. 9304 (Feb. 16, 2012).
2 See *Natioal Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units—Revocation of the 2020 Reconsideration, and Affirmation of the Appropriate and Necessary Supplemental Finding*, Notice of Proposed Rulemaking, EPA-HQ-OAR-2018-0794, 87 Fed. Reg. 7624.
3 CAA § 110(a)(2)(D)(i)(I).
4 *Revised Cross-State Air Pollution Rule Update for the 2008 Ozone NAAQS*, Docket No. EPA-HQ-OAR-2020-0272; FRL-10013-42- OAR, 85 Fed. Reg. 23054 (Apr. 30, 2021).
5 See *Federal Implementation Plan Addressing Regional Ozone Transport for the 2015 Ozone National Ambient Air Quality Standard*, Docket No. EPA-HQ-OAR-2021-0668; FRL 8670-01-OAR, 87 Fed. Reg. 20036 (April 6, 2022).
6 See *Reconsideration of the National Ambient Air Quality Standards for Particulate Matter.* Proposed Rule, Docket No. EPA-HQ-OAR-2015-0072; FRL-8635-01- OAR, 88 Fed. Reg. 5558 (January 27, 2023).
7 *Prevention of Significant Deterioration (PSD) and Nonattainment New Source Review (NNSR): Project Emissions Accounting*, EPA Docket No. EPA-HQ-OAR-2018-0048; FRL-9997-95-OAR, 84 Fed. Reg. 39244 (Aug. 9, 2019).
8 See 40 CFR § 63.6640(f).

individually or as part of a portfolio if it cannot meet its capacity market obligations as a result of emissions standards.

- **Greenhouse Gas Emissions.** On June 30, 2022, the Supreme Court held that Section 111(d) of the CAA did not provide authority under the major questions doctrine to regulate carbon emissions in the manner proposed.[9] Both the EPA's Affordable Clean Energy (ACE) rule and the Clean Power Plan (CPP), which were promulgated under Section 111(d) of the CAA, are expected to be vacated on remand.
- **Cooling Water Intakes.** An EPA rule implementing Section 316(b) of the Clean Water Act (CWA) requires that cooling water intake structures reflect the best technology available for minimizing adverse environmental impacts.[10]
- **Waters of the United States.** On December 30, 2022, the EPA and the Army Corps of Engineers announced a final rule revising the definition of WOTUS.[11] The rule will become effective on March 20, 2023.
- **Effluents.** Under the CWA, the EPA regulates (National Pollutant Discharge Elimination System (NPDES)) discharges from and intakes to power plants, including water cooling systems at steam electric power generating stations. The EPA has recently been strengthening certain discharge limits applicable to steam generating units, and some plant owners have already indicated an intent to close certain generating units as a result.
- **Coal Ash.** The EPA administers the Resource Conservation and Recovery Act (RCRA), which governs the disposal of solid and hazardous waste.[12] The EPA has adopted significant changes to the implementing regulations that will require closing noncompliant impoundments, and, as a result, the host power plant. The EPA is implementing a process for extensions to as late as October 17, 2028. The EPA is reviewing applications received from PJM plant owners for extensions of the deadline for compliance with the revised Coal Combustion Residuals Rule.

State Environmental Regulation

- **Regional Greenhouse Gas Initiative (RGGI).** The Regional Greenhouse Gas Initiative (RGGI) is a CO_2 emissions cap and trade agreement among Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New Jersey, New York, Rhode Island, Vermont and Virginia that applies to power generation facilities. New Jersey rejoined on January 1, 2020.[13] Virginia joined RGGI on January 1, 2021. Pennsylvania took action to join RGGI on April 23, 2022, but such action has been enjoined by court order on appeal.[14] [15] A decision on the merits of the appeal is pending at the Supreme Court of Pennsylvania. The auction price in the March 8, 2023 RGGI auction was $12.50 per short ton, or $13.78 per metric tonne.
- **Illinois Climate and Equitable Jobs Act (CEJA).** On September 16, 2021, the Climate and Equitable Jobs Act (CEJA) became effective. CEJA created an expanded nuclear subsidy program. CEJA mandates that all fossil fuel plants close by 2045. CEJA established emissions caps for investor owned, gas-fired units with three years of operating history, effective October 1, 2021, on a rolling 12 month basis. More than 10,000 MW of capacity are currently affected.
- **Carbon Price.** If the price of carbon were $50.00 per metric tonne, short run marginal costs would increase by $24.45 per MWh or 70.9 percent for a new combustion turbine (CT) unit, $16.85 per MWh or 74.8 percent for a new combined cycle (CC) unit and $43.09 per MWh or 82.4 percent for a new coal plant (CP) for the first three months of 2023.

State Renewable Portfolio Standards

- **RPS.** In PJM, ten of 14 jurisdictions have enacted legislation requiring that a defined percentage of retail suppliers' load be served by renewable resources, for which definitions vary. These are typically known as renewable portfolio standards, or RPS. As of March 31, 2023, Delaware,

9 *West Virginia v. EPA*, No. 20-1530 (S. Ct. of the U.S.).
10 See EPA, *National Pollutant Discharge Elimination System—Final Regulations to Establish Requirements for Cooling Water Intake Structures at Existing Facilities and Amend Requirements at Phase I Facilities*, EPA-HQ-OW-2008-0667, 79 Fed. Reg. 48300 (Aug. 15, 2014).
11 *See Revised Definition of "Waters of the United States,"* Final Rule, Docket No. [EPA-HQ-OW-2021-0602; FRL-6027.4-01-OW, 88 Fed. Reg. 3004 (January 18, 2023)
12 42 U.S.C. §§ 6901 *et seq.*
13 "Statement on New Jersey Greenhouse Gas Rule," RGGI Inc., (June 17, 2019) <https://www.rggi.org/sites/default/files/Uploads/Press-Releases/2019_06_17_NJ_Announcement_Release.pdf>.
14 CO2 Budget Trading Program, 52 Pa.B. 2471 (April 23, 2022), codified 25 Pa. Code Ch. 145; *see also* Executive Order-2019-07. Commonwealth Leadership in Addressing Climate Change through Electric Sector Emissions Reductions, Tom Wolf, Governor, October 3, 2019, <https://www.governor.pa.gov/newsroom/executive-order-2019-07-commonwealth-leadership-in-addressing-climate-change-through-electric-sector-emissions-reductions/> .
15 See *Ramez Ziadeh, et al. v. Pennsylvania Legislative Reference Bureau*, Memorandum Opinion, Commonwealth Court of Pennsylvania Case No. No. 41 M.D. 2022 (July 8, 2022); *Ramez Ziadeh, et al. v. Pennsylvania Legislative Reference* Bureau, Order Granting Application to Vacate, Commonwealth Court of Pennsylvania Case No. No. 41 M.D. 2022 (July 25, 2022).

Illinois, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Virginia and Washington, DC have renewable portfolio standards. Indiana has a voluntary renewable portfolio standard. Kentucky, Tennessee and West Virginia do not have renewable portfolio standards.

- **RPS Cost.** The cost of complying with RPS, as reported by the states, is $7.2 billion over the seven year period from 2014 through 2020, an average annual RPS compliance cost of $1.0 billion. The compliance cost for 2020, the most recent year with almost complete data, was $1.5 billion.[16]

Emissions Controls in PJM Markets

- **Regulations.** Environmental regulations affect decisions about emission control investments in existing units, investment in new units and decisions to retire units. As a result of environmental regulations and agreements to limit emissions, many PJM units burning fossil fuels have installed emission control technology.
- **Emissions Controls.** In PJM, as of March 31, 2023, 96.0 percent of coal steam MW had some type of flue-gas desulfurization (FGD) technology to reduce SO_2 emissions, 99.8 percent of coal steam MW had some type of particulate matter (PM) control, and 99.8 percent of coal steam MW had NO_X emission control technology. All coal steam units in PJM are compliant with the state and federal emissions limits established by MATS.

Renewable Generation

- **Renewable Generation.** Wind and solar generation was 5.8 percent of total generation in PJM for the first three months of 2023. RPS Tier I generation was 7.4 percent of total generation in PJM and RPS Tier II generation was 1.9 percent of total generation in PJM for the first three months of 2023. Only Tier I generation is defined to be renewable but Tier 1 includes some carbon emitting generation.
- PJM states with RPS rely heavily on imports and generation from behind the meter resources for RPS compliance. In the first three months of 2023, Tier I generation in PJM met only 58.4 percent of the Tier I RPS requirements.

16 The 2020 compliance cost value for PJM states does not include Illinois, Michigan or North Carolina. Based on past data these states generally account for 3.0 percent of the total RPS compliance cost of PJM states.

Recommendations

- The MMU recommends that renewable energy credit markets based on state renewable portfolio standards be brought into PJM markets as they are an increasingly important component of the wholesale energy market. The MMU recommends that there be a single PJM operated forward market for RECs, for a single product based on a common set of state definitions of renewable technologies, with a single clearing price, trued up to real time delivery. (Priority: High. First reported 2010. Status: Not adopted.)
- The MMU recommends that PJM provide a full analysis of the impact of carbon pricing on PJM generating units and carbon pricing revenues to the PJM states in order to permit the states to consider a potential agreement on the development of a multistate framework for carbon pricing and the distribution of carbon revenues. (Priority: High. First reported 2018. Status: Not adopted.)
- The MMU recommends that jurisdictions with a renewable portfolio standard make the price and quantity data on supply and demand more transparent. (Priority: Low. First reported 2018. Status: Not adopted.)
- The MMU recommends that the Commission reconsider its disclaimer of jurisdiction over RECs markets because, given market changes since that decision, it is clear that RECs materially affect jurisdictional rates. (Priority: Low. First reported 2018. Status: Not adopted.)
- The MMU recommends that load and generation located at separate nodes be treated as separate resources in order to ensure that load and generation face consistent incentives throughout the markets. (Priority: High. First reported 2019. Status: Not adopted.)
- The MMU recommends that emergency stationary RICE be prohibited from participation as DR either when registered individually or as part of a portfolio if it cannot meet the capacity market requirements to be DR as a result of emissions standards that impose environmental run hour limitations. (Priority: Medium. First reported 2019. Status: Not adopted.)

Conclusion

Environmental requirements and renewable energy mandates at both the federal and state levels have a significant impact on the cost of energy and capacity in PJM markets.

Environmental requirements and initiatives at both the federal and state levels, and state renewable energy mandates and associated subsidies have resulted in the construction of substantial amounts of renewable capacity in the PJM footprint, especially wind and solar resources, and the retirement of emitting resources. Renewable energy credit (REC) markets created by state programs, and federal tax credits have significant impacts on PJM wholesale markets. But state renewables programs in PJM are not coordinated with one another, are generally not consistent with the PJM market design or PJM prices, have widely differing objectives, including supporting some emitting resources, have widely differing implied prices of carbon and are not transparent on pricing and quantities. The effectiveness of state renewables programs would be enhanced if they were coordinated with one another and with PJM markets, and if they increased transparency. States could evaluate the impacts of a range of carbon prices if PJM would provide a full analysis of the impact of carbon pricing on PJM generating units and carbon pricing revenues to the PJM states in order to permit the states to consider a potential agreement on the development of a multistate framework for carbon pricing and the distribution of carbon revenues. A single carbon price across PJM, established by the states, would be the most efficient way to reduce carbon output, if that is the goal.

But in the absence of a PJM market carbon price, a single PJM market for RECs would contribute significantly to market efficiency and to the procurement of renewable resources in a least cost manner. Ideally, there would be a single PJM operated forward market for RECs, for a single product based on a common set of state definitions of renewable technologies, with a single clearing price, trued up to real-time delivery. States would continue to have the option to create separate RECs for additional products that did not fit the product definition, e.g. waste coal, trash incinerators, or black liquor.

RECs are an important mechanism used by PJM states to implement environmental policy. RECs clearly affect prices in the PJM wholesale power market. Some resources are not economic except for the ability to purchase or sell RECs. RECs provide out of market payments to qualifying renewable resources, primarily wind and solar. The credits provide an incentive to make negative energy offers and more generally provide an incentive to enter the market, to remain in the market and to operate whenever possible. These subsidies affect the offer behavior and the operational behavior of these resources in PJM markets and in some cases the existence of these resources and thus the market prices and the mix of clearing resources.

RECs markets are, as an economic fact, integrated with PJM markets including energy and capacity markets, but are not formally recognized as part of PJM markets. It would be preferable to have a single, transparent market for RECs operated by the PJM RTO on behalf of the states that would meet the standards and requirements of all states in the PJM footprint. This would provide better information for market participants about supply and demand and prices and contribute to a more efficient and competitive market and to better price formation. This could also facilitate entry by qualifying renewable resources by reducing the risks associated with lack of transparent market data.

Existing REC markets are not consistently or adequately transparent. Data on REC prices, clearing quantities and markets are not publicly available for all PJM states. The economic logic of RPS programs and the associated REC and SREC prices is not always clear. The price of carbon implied by REC prices ranges from $16.69 per tonne in Ohio to $35.62 per tonne in New Jersey. The price of carbon implied by SREC prices ranges from $81.62 per tonne in Pennsylvania to $842.51 per tonne in Washington, DC. The effective prices for carbon compare to the RGGI clearing price in March 2023 of $13.78 per tonne and to the social cost of carbon which is estimated in the range of $50 per tonne.[17] The impact on the cost of generation from a new combined cycle unit of a $50 per tonne carbon price would be $16.85 per MWh.[18] The impact of

17 "Technical Update of the Social Cost of Carbon for Regulatory Impact Analysis – Under Executive Order 12899," Interagency Working Group on the Social Cost of Greenhouse Gases, United States Government, (Aug. 2016), <https://19january2017snapshot.epa.gov/sites/production/files/2016-12/documents/sc_co2_tsd_august_2016.pdf>.

18 The cost impact calculation assumes a heat rate of 6.296 MMBtu per MWh and a carbon emissions rate of 0.05290995 tonne per MMBtu. The $800 per tonne carbon price represents the approximate upper end of the carbon prices implied by the 2022 REC and SREC prices in the PJM jurisdictions with RPS. Additional cost impacts are provided in Table 8-7.

an $800 per tonne carbon price would be $269.59 per MWh. This wide range of implied carbon prices is not consistent with an efficient, competitive, least cost approach to the reduction of carbon emissions.

In addition, even the explicit environmental goals of RPS programs are not clear. While RPS is frequently considered to target carbon emissions, Tier 1 resources include some carbon emitting generation and Tier 2 resources include additional carbon emitting generation.

PJM markets provide a flexible mechanism for incorporating the costs of environmental controls and meeting environmental requirements in a cost effective manner. Costs for environmental controls are part of offers for capacity resources in the PJM Capacity Market. The costs of emissions credits are included in energy offers. PJM markets also provide a flexible mechanism that incorporates renewable resources and the impacts of renewable energy credit markets, and ensures that renewable resources have access to a broad market. PJM markets provide efficient price signals that permit valuation of resources with very different characteristics when they provide the same product.

If the states chose this policy option, PJM markets could also provide a flexible mechanism to limit carbon output, for example by incorporating a consistent carbon price in unit offers which would be reflected in PJM's economic dispatch. If there is a social decision to limit carbon output, a consistent carbon price would be the most efficient way to implement that decision. The states in PJM could agree, if they decided it was in their interests, with the appropriate information, on a carbon price and on how to allocate the revenues from a carbon price that would make all states better off. A mechanism like RGGI leaves all decision making with the states. The carbon price would not be FERC jurisdictional or subject to PJM decisions. The MMU continues to recommend that PJM provide a full analysis of the impact of carbon pricing on PJM generating units and carbon pricing revenues to the PJM states in order to permit the states to consider a potential agreement on the development of a multistate framework for carbon pricing and the distribution of carbon revenues. The results of the analysis would include the impact on the dispatch of every unit, the impact on energy prices and the carbon pricing revenues that would flow to each state.

For example, states receiving high levels of revenue could shift revenue to states disproportionately hurt by a carbon price if they believed that all states would be better off as a result. A carbon price would also be an alternative to specific subsidies to individual nuclear power plants and to the current wide range of implied carbon prices embedded in RPS programs and instead provide a market signal to which any resource could respond. The imposition of specific and prescriptive environmental dispatch rules would, in contrast, pose a threat to economic dispatch and efficient markets and create very difficult market power monitoring and mitigation issues. The provision of subsidies to individual units creates a discriminatory regime that is not consistent with competition. The use of inconsistent implied carbon prices by state is also inconsistent with an efficient market and inconsistent with the least cost approach to meeting state environmental goals.

The annual average cost of complying with RPS over the seven year period from 2014 through 2020 for the nine jurisdictions that had RPS was $1.0 billion, or a total of $7.2 billion over seven years. The RPS compliance cost for 2020, the most recent year for which there is almost complete data, was $1.5 billion.[19] RPS costs are payments by customers to the sellers of qualifying resources. The revenues from carbon pricing flow to the states.

If all the PJM states participated in a regional carbon market, the estimated revenue returned to the states/customers from selling carbon allowances would be approximately $3.5 billion per year if the carbon price were $12.50 per short ton and emissions levels were five percent below 2021 emission levels. If all the PJM states participated in a regional carbon market, the estimated revenue returned to the states/customers from selling carbon allowances would be approximately $14.1 billion if the carbon price were $50 per short ton and emission levels were five percent below 2021 levels. If only the current RPS states participated in a regional carbon market, the estimated revenue returned to the states/customers from selling carbon allowances at $12.50 per short ton would be about $2.3 billion. The costs of a carbon price

19 The 2020 compliance cost value for PJM states does not include Illinois, Michigan or North Carolina. Based on past data these states generally account for 3.0 percent of the total RPS compliance cost of PJM states.

are the impact on energy market prices, net of the revenue returned to states/customers.

Federal Environmental Regulation

The U.S. Environmental Protection Agency (EPA) administers the Clean Air Act (CAA), the Clean Water Act (CWA) and the Resource Conservation and Recovery Act (RCRA), all of which address pollution created by electric power production. The administration of these statutes is relevant to the operation of PJM markets.[20]

The CAA regulates air emissions by providing for the establishment of acceptable levels of emissions of hazardous air pollutants. The EPA issues technology based standards for major sources and area sources of emissions.[21] [22]

The CWA regulates discharges from point sources that affect water quality and temperature.

The Resource Conservation and Recovery Act (RCRA) regulates the disposal of solid and hazardous waste.[23] Regulation of coal ash or coal combustion residuals affects coal fired power plants.

The EPA's actions have affected and will continue to affect the cost to build and operate generating units in PJM, which in turn affects wholesale energy prices and capacity prices.

CAA: NESHAP/MATS

Section 112 of the CAA requires the EPA to promulgate emissions control standards, known as the National Emission Standards for Hazardous Air Pollutants (NESHAP), from both new and existing area and major sources. On December 21, 2011, the EPA issued its Mercury and Air Toxics Standards rule (MATS), which applies the CAA maximum achievable control technology (MACT) requirement to new or modified sources of emissions of mercury and arsenic, acid gas, nickel, selenium and cyanide.

On February 15, 2023, the EPA issued a final action reaffirming that it remains appropriate and necessary to regulate hazardous air pollutants (HAP), including mercury, from power plants after considering cost.[24] This action revokes a 2020 finding that it was not appropriate and necessary to regulate coal and oil fired power plants under CAA § 112, and restores the basis for the MATS rule.[25] Restoration of the appropriate and necessary finding removes the possibility of a challenge to the MATS rule if applied to the proposed construction or upgrade of a power plant.

On April 3, 2023, the EPA proposed to strengthen and update the MATS rule to reflect recent developments in control technologies and the performance of coal fired plants.[26] The core proposal would revise the (non Hg) PM emission standard, from 0.030 to 0.010 lbs/MMBtu.[27] The EPA believes that the tighter standard could affect up to nine percent of U.S. coal units not already planning to retire.[28] The EPA projects that about 500 MW of coal fired capacity would become uneconomic to maintain by 2028 as a result of the proposed update.[29]

CAA: NAAQS/CSAPR

The CAA requires each state to attain and maintain compliance with particulate matter (PM) and ozone national ambient air quality standards (NAAQS).[30] Under NAAQS, the EPA establishes emission standards for six air pollutants, including NO_X, SO_2, O_3 at ground level, PM, CO, and Pb, and approves state plans to implement these standards, known as State Implementation Plans (SIPs).

20 For more details, see the *2022 State of the Market Report for PJM*, Vol. II, Appendix H: "Environmental and Renewable Energy Regulations."

21 42 U.S.C. § 7401 et seq. (2000).

22 The EPA defines a "major source" as a stationary source or group of stationary sources that emit or have the potential to emit 10 tons per year or more of a hazardous air pollutant or 25 tons per year or more of a combination of hazardous air pollutants. An "area source" is any stationary source that is not a major source.

23 42 U.S.C. §§ 6901 *et seq.*

24 See *National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units—Revocation of the 2020 Reconsideration, and Affirmation of the Appropriate and Necessary Supplemental Finding*, Notice of Proposed Rulemaking, EPA-HQ-OAR-2018-0794, 88 Fed. Reg. 13956 (March 6, 2023).

25 See *National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units—Reconsideration of Supplemental Finding and Residual Risk and Technology Review*, Docket No. EPA-HQ-OAR-2018-0794, 85 Fed. Reg. 31286 (May 22, 2020).

26 See *National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units Review of the Residual Risk and Technology Review*, Docket No. EPA-HQ-OAR-2018-0794.

27 *Id.* at 51–52.

28 *Id.*

29 *Id.* at 119.

30 The particulate matter (PM) regulated under the CAA is classified as either PM_{10}, which refers to PM less than 10 microns, and $PM_{2.5}$, which refers PM less than 2.5 microns. $PM_{2.5}$ is referred to as fine particular matter and poses the greatest risk to health. Examples of $PM_{2.5}$ include combustion particles, metals, and organic compounds.

On January 6, 2023, the EPA proposed to lower the primary annual $PM_{2.5}$ standard to 9.0 to 10.0 $\mu g/m^3$ from 12.0 $\mu g/m^3$.[31] The proposal does not change other $PM_{2.5}$ standards. The proposal responds to the directive in Executive Order 13990 for review of a 2020 Particulate Matter NAAQS Decision that left $PM_{2.5}$ standards unchanged.

In January 2015, the EPA began implementation of the Cross-State Air Pollution Rule (CSAPR) to address the CAA's requirement that each state prohibit emissions that significantly interfere with the ability of another state to meet NAAQS. CSAPR requires specific states in the eastern and central United States to reduce power plant emissions of SO_2 and NO_X that cross state lines and contribute to ozone and fine particle pollution in other states. CSPAR requires reductions to levels consistent with the 1997 ozone and fine particle emissions and 2006 fine particle emission NAAQS. CSAPR covers 28 states, including all of the PJM states except Delaware, and also excluding the District of Columbia.

On March 15, 2021, in response to a court holding in *Wisconsin v. EPA*,[32] the EPA finalized increases to the good neighbor obligations (i.e. reduced allowable emissions) under the 2008 ozone NAAQS for 12 states.[33] Eleven of the affected states are PJM states: Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, Ohio, Pennsylvania, Tennessee, Virginia, and West Virginia. The EPA determined that Tennessee's emissions budget "fully eliminated the state's significant contribution to downwind nonattainment and interference with maintenance of the 2008 ozone NAAQS."[34] For the remaining PJM states, projected 2021 emissions were found to contribute at or above a threshold of 1 percent of the NAAQS (0.75 ppb) to the identified nonattainment and/or maintenance problems in downwind states.[35] Starting with the 2021 ozone season for emissions trading under CSAPR, the new FIPs require power plants in the affected states (also including Louisiana and New York) to participate in a new CSAPR NO_x Ozone Season Group 3 Trading Program.[36] Participation in the more stringent new program would replace the obligation to participate in the existing CSAPR NO_x Ozone Season Group 2 Trading Program.[37] [38]

On March 15, 2023, the EPA finalized Federal Implementation Plan (FIP) requirements for 23 states that addresses the contribution of those states to problems in other states in attaining and maintaining the 2015 Ozone NAAQS.[39] The rule resolves the CAA good neighbor obligations of the affected states. The FIP requirements establish ozone season NO_X emissions budgets for electric generating units in the following PJM states: Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, Ohio, Pennsylvania, Virginia and West Virginia. The list of PJM jurisdictions excludes North Carolina, the District of Columbia, Tennessee and Delaware. Electric generating units in the indicated states would be required to participate in a revised version of the CSAPR NO_X Ozone Season Group 3 Trading Program that was previously established in the 2021 CSAPR Update.

The EPA's emissions budgets for each PJM state for each ozone season for 2023 through 2029, and beyond are shown in Table 8-1.

Table 8-1 CSAPR NO_x ozone season group 3 state budgets: 2023 through 2029[40]

	Emissions Budget (Tons)							
PJM State	2023	2024	2025	2026	2027	2028	2029	2030+
Illinois	7,474	7,325	7,325	5,889*	5,363*	4,555*	4,050*	*
Indiana	12,440	11,413	11,413	8,410*	8,135*	7,280*	5,808*	*
Kentucky	13,601	12,999	12,472	10,190*	7,908*	7,837*	7,392*	*
Maryland	1,206	1,206	1,206	842*	842*	842*	842*	*
Michigan	10,727	10,275	10,275	6,743*	5,691*	5,691*	4,656*	*
New Jersey	773	773	773	773*	773*	773*	773*	*
Ohio	9,110	7,929	7,929	7929*	7,929*	6,911*	6,409*	*
Pennsylvania	8,138	8,138	8,138	7,512*	7,158*	7,158*	4,828*	*
Virginia	3,143	2,756	2,756	2,565*	2,373*	2,373*	1,951*	*
West Virginia	13,791	11,958	11,958	10,818*	9,678*	9,678*	9,678*	*

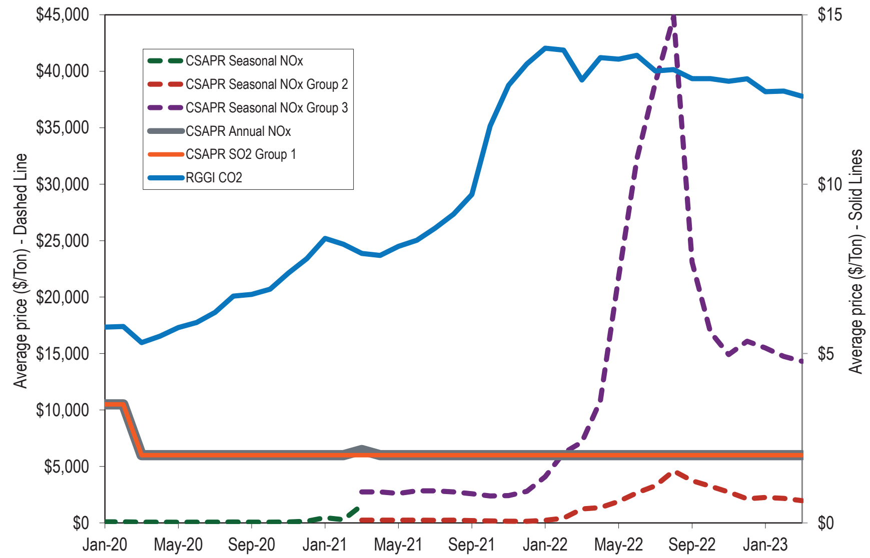
*The budget for these years will be subsequently determined and equal the greater of the value above or that derived from the dynamic budget methodology.

31 *See Reconsideration of the National Ambient Air Quality Standards for Particulate Matter.* Proposed Rule, Docket No. EPA-HQ-OAR-2015-0072; FRL-8635-01- OAR, 88 Fed. Reg. 5558 (January 27, 2023).
32 Wisconsin v. EPA, 938 F.3d 303, 318-20 (D.C. Cir. 2019).
33 *Revised Cross-State Air Pollution Rule Update for the 2008 Ozone NAAQS*, Docket No. EPA-HQ-OAR-2020-0272; FRL-10013-42- OAR, 85 Fed. Reg. 23054 (Apr. 30, 2021).
34 *Id.* at 23066.
35 *Id.* at 23085-23086.
36 *Id.* at 23121.
37 *Id.*
38 On April 30, 2021, the MMU sent a market message to PJM market participants explaining how to account for the changes in cost-based offers. *See* "CSAPR Ozone Season Changes," <https://www.monitoringanalytics.com/reports/Market_Messages/Messages/IMM_CSAPR_Ozone_Season_Changes_20210430.pdf>
39 See *Federal "Good Neighbor Plan" for the 2015 Ozone National Ambient Air Quality*, Final Rule, EPA-HQ-OAR-2021-0668.
40 *Id.* at 35 (Table I.B-1).

Figure 8-1 shows average, monthly settled prices for NO_x and SO_2 emissions allowances including CSAPR related allowances for January 2020 through March 2023. Figure 8-1 also shows the average, monthly settled price for the Regional Greenhouse Gas Initiative (RGGI) CO_2 allowances.

In the first three months of 2023, CSAPR annual NO_X prices were the same on average as the price in the first three months of 2022. The group 2 CSAPR Seasonal NO_X price averaged $2,130 in the first three months of 2023, a 239.9 percent increase over the group 2 CSAPR Seasonal NO_X price for the first three months of 2022.[41] The group 3 CSAPR Seasonal NO_X price averaged $14,849 in the first three months of 2023, a 155.4 percent increase over the group 3 CSAPR Seasonal NO_X price for the first three months of 2022.[42] The components of real-time LMP analysis shows that NO_x cost contributed $0.00 to the load-weighted average real-time LMP in the first three months of 2023, compared to $0.19 in first three months of 2022.[43] CO_2 cost contributed $1.61 to the load-weighted average real-time LMP in the first three months of 2023, compared to $1.68 in first three months of 2022.[44]

Figure 8-1 Spot monthly average emission price comparison: January 2020 through March 2023



CAA: NSR

Parts C and D of Title I of the CAA provide for New Source Review (NSR) in order to prevent new projects and projects receiving major modifications from increasing emissions in areas currently meeting NAAQS or from inhibiting progress in areas that do not.[45] NSR requires permits before construction commences. In PJM, permits are issued by state environmental regulators, or in a process involving state and regional EPA regulators.[46]

NSR review applies a two part analysis to projects at facilities such as power plants, some of which involve multiple units and combinations of new and existing units. The first part considers whether a modification would cause a "significant emission increase" of a regulated NSR pollutant. The second part

41 Tennessee is the only PJM state that remains in the CSAPR NO_x Ozone Season Group 2 Trading Program.
42 Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, Ohio, Pennsylvania, Virginia, and West Virginia participate in the CSAPR NO_x Ozone Season Group 3 Trading Program.
43 See Components of LMP in 2023 Quarterly State of the Market Report for PJM: January through March, Section 3: Energy Market.
44 Id.

45 42 U.S.C § 7470 et seq.
46 CAA permitting in EPA Region 2 (New Jersey) is the responsibility of the state's environmental regulatory authority; CAA permitting in Region 3 (Delaware, District of Columbia, Maryland, Pennsylvania, Virginia, West Virginia) is the shared responsibility of each state's environmental regulatory authority and EPA Region 3; CAA permitting in Region 4 (Kentucky and North Carolina) is the shared responsibility of each state's environmental regulatory authority and EPA Region 4; CAA permitting in EPA Region 5 (Illinois, Indiana, Michigan and Ohio) is the responsibility of each state's environmental regulatory authority.

considers whether any identified increase is also a "significant net emission increase."

On April 21, 2022, the EPA issued for public input a draft technical non regulatory white paper on control techniques and measures that could reduce GHG emissions from new stationary CTs.[47]

CAA: RICE

On January 14, 2013, the EPA signed a final rule amending its rules regulating emissions from a wide variety of stationary reciprocating internal combustion engines (RICE). RICE include certain types of electrical generation facilities like diesel engines typically used for backup, emergency or supplemental power, including facilities located behind the meter. These rules include: National Emission Standard for Hazardous Air Pollutants (NESHAP) for Reciprocating Internal Combustion Engines (RICE); New Source Performance Standards (NSPS) of Performance for Stationary Spark Ignition Internal Combustion Engines; and Standards of Performance for Stationary Compression Ignition Internal Combustion Engines (collectively RICE Rules). The RICE Rules apply to emissions such as formaldehyde, acrolein, acetaldehyde, methanol, CO, NO_X, volatile organic compounds (VOCs) and PM.

EPA regulations require that RICE that do not meet EPA emissions standards (emergency stationary RICE) may operate for only 100 hours per year and only to provide emergency DR during an Energy Emergency Alert 2 (EEA2), or if there are five percent voltage/frequency deviations.[48] Under PJM rules, an EEA2 is automatically triggered when PJM initiates an emergency load response event. Demand resources that rely on RICE to provide load reductions are constrained to a maximum of 100 hours.

PJM does not prevent emergency stationary RICE that does not meet emissions standards from participating in PJM markets as DR. Some emergency stationary RICE that does not meet emissions standards are now included in DR portfolios. Emergency stationary RICE should be prohibited from participation as DR either when registered individually or as part of a portfolio if it does not meet emissions standards. Emergency RICE with a limit of 100 hours per year cannot comply with the requirement to be available during the entire delivery year to be a capacity resource. PJM should not allow locations that rely upon emergency stationary RICE to register individually or in portfolios. Registration of DR should be based on a finding that registered locations are capable of providing load reductions without an hourly limit. Reliance on the prospect of penalties to deter registration of ineligible resources as DR in lieu of a substantive ex ante review is not appropriate. The MMU recommends that emergency stationary RICE be prohibited from participation as DR either when registered individually or as part of a portfolio if it cannot meet the capacity market requirements to be DR as a result of emissions standards that impose environmental run hour limitations.

CAA: Greenhouse Gas Emissions

The EPA regulates CO_2 as a pollutant using CAA provisions that apply to pollutants not subject to NAAQS.[49] [50]

Executive Order 14057 requires the federal government to achieve "100 percent carbon pollution-free electricity on a net annual basis by 2030, including 50 percent 24/7 carbon pollution-free electricity by 2030."[51]

The U.S. Court of Appeals for the Seventh Circuit has determined that a government agency can reasonably consider the global benefits of carbon emissions reduction against costs imposed in the U.S. by regulations in analyses known as the "Social Costs of Carbon."[52] The Court rejected claims raised by petitioners that raised concerns that the Social Cost of Carbon estimates were arbitrary, were not developed through transparent processes,

47 The draft white paper can be accessed here: <https://www.epa.gov/system/files/documents/2022-04/epa_ghg-controls-for-combustion-turbine-egus_draft-april-2022.pdf>.

48 Emergency Operations, EOP-011-1, North American Electric Reliability Corporation, <https://www.nerc.com/pa/Stand/Reliability%20Standards/EOP-011-1.pdf> (Accessed March 2, 2020).

49 See CAA § 111.

50 On April 2, 2007, the U.S. Supreme Court overruled the EPA's determination that it was not authorized to regulate greenhouse gas emissions under the CAA and remanded the matter to the EPA to determine whether greenhouse gases endanger public health and welfare. Massachusetts v. EPA, 549 U.S. 497. On December 7, 2009, the EPA determined that greenhouse gases, including carbon dioxide, methane, nitrous oxide, hydrofluorocarbons, perfluorocarbons, and sulfur hexafluoride, endanger public health and welfare. See *Endangerment and Cause or Contribute Findings for Greenhouse Gases Under Section 202(a) of the Clean Air Act*, 74 Fed. Reg. 66496, 66497 (Dec. 15, 2009). In a decision dated June 26, 2012, the U.S. Court of Appeals for the D.C. Circuit upheld the endangerment finding, rejecting challenges brought by industry groups and a number of states. Coalition for Responsible Regulation, Inc., et al. v. EPA, No 09-1322.

51 See Executive Order on Catalyzing Clean Energy Industries and Jobs Through Federal Sustainability, Section 102(a)(i), Executive Order 14057 (December 8, 2021), <https://www.whitehouse.gov/briefing-room/presidential-actions/2021/12/08/executive-order-on-catalyzing-clean-energy-industries-and-jobs-through-federal-sustainability/?utm_medium=email&utm_source=govDelivery>.

52 See Zero Zone, Inc., et al., v. U.S. Dept. of Energy, et al., Case Nos. 14-2147, et al., Slip Op. (Aug. 8, 2016).

and were based on inputs that were not peer reviewed.[53] Although the decision applies only to the Department of Energy's regulations of manufacturers, it bolsters the ability of the EPA and state regulators to rely on Social Cost of Carbon analyses.

Executive Order 13990, Section 6, established an Interagency Working Group (IWG) on the Social Cost of Greenhouse Gases. The group developed estimates for the social cost of carbon (SCC), the social cost of nitrous oxide (SCN), and the social cost of methane (SCM). The cost estimates will be used by EPA and other agencies to determine the social benefits of reducing greenhouse gas emissions when conducting cost-benefit analyses of regulatory and other actions. On July 27, 2022, the U.S. District Court for the Western District of Louisiana enjoined reliance on the IWG's SCC estimates.[54] On April 3, 2023, the U.S. Court of Appeals for the Fifth Circuit dismissed the challenge for lack of standing and vacated the injunction, explaining that agencies' use of the estimates is discretionary and the alleged harms are conjectural.[55]

The EPA has been using the IWG's interim value for SCC of $51 per metric ton of CO_2. In a proposed rule reforming standards for reducing emissions of GHGs from the Crude Oil and Natural Gas source category, the EPA proposes increasing that value to $190.[56] Support for the increase was included in a report attached to the proposed rule that is now subject to public comment.[57]

Effective October 23, 2015, the EPA placed national limits on the amount of CO_2 that new, modified or reconstructed fossil fuel fired steam power plants would be allowed to emit based on the best system of emission reductions (BSER) determined by the EPA (2015 GHG NSR Rule).[58] Effective March 15, 2021, the EPA revised the 2015 GHG NSR Rule by increasing the allowable emissions and eliminating the requirement for carbon capture for new coal units.[59]

CWA: WOTUS Definition and Effluents

WOTUS

The Clean Water Act (CWA) applies to navigable waters, which are defined as waters of the United States (WOTUS).[60] [61] The definition of WOTUS is a threshold issue that determines the hydrological scope of the CWA's applicability. Over the past decade, attempts to define WOTUS have been repeatedly addressed by the Courts, and no durable definition has resulted.[62] Establishing a durable definition is important to the electric industry, which needs to plan for compliance with the CWA and related regulations.

On December 30, 2022, the EPA and the Army Corps of Engineers announced a final rule revising the definition of WOTUS.[63] The Rule defines WOTUS to include: (i) traditional navigable waters, the territorial seas, and interstate waters; (ii) impoundments of WOTUS; (iii) tributaries to traditional navigable waters, the territorial seas, interstate waters, impoundments when the tributaries meet either the relatively permanent standard or the significant nexus standard; (iv) wetlands, including jurisdictional adjacent wetlands; and (v) intrastate lakes and ponds, streams, or wetlands that meet either the relatively permanent standard or the significant nexus standard.[64] The rule became effective on March 20, 2023, except that, due to preliminary injunctions issued in court proceedings challenging the rule, the rule did not become effective in 26 states, including PJM states Indiana, Ohio, Tennessee, Virginia, West Virginia, and Kentucky.

53 *Id.*

54 *See* Louisiana v. Biden, Order, Civ. No. 2:21-CV-1074-JDC-KK (July 27, 2022).

55 *See* Louisiana v. Biden, Case No. 2:21-CV-1074, slip. op. (5th Cir. April 3, 2023) at 8–15.

56 *See Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review*, EPA Docket No. EPA–HQ–OAR–2021–0317; FRL–8510–04–OAR, 87 Fed. Reg. 74702 (December 6, 2022).

57 *See Report on the Social Cost of Greenhouse Gases: Estimates Incorporating Recent Scientific Advances*, EPA Docket ID No. EPA-HQ-OAR-2021-0317 (September 2022).

58 *Standards of Performance for Greenhouse Gas Emissions from New Stationary Sources: Electric Utility Generating Units*, Proposed Rule, EPA-HQ-OAR-2013-0495, 90 Fed. Reg. 205 (October 23, 2015) ("2015 GHG NSR Rule"); 40 CFR Part 60, subpart TTTT.

59 *Pollutant-Specific Significant Contribution Finding for Greenhouse Gas Emissions From New, Modified, and Reconstructed Stationary Sources: Electric Utility Generating Units, and Process for Determining Significance of Other New Source Performance Standards Source Categories*, EPA–HQ–OAR–2013–0495; FRL–10019–30– OAR, 86 Fed. Reg. 2542 (Jan. 13, 2018) ("2021 GHG NSR").

60 33 U.S.C. 1251 et seq.; 33 U.S.C. § 1362(7) ("*The term "navigable waters" means the waters of the United States, including the territorial seas.*").

61 For more details, see the *2019 State of the Market Report for PJM*, Volume II, Appendix H: "Environmental and Renewable Energy Regulations."

62 See, e.g., Rapanos v. U.S., 547 U.S. 715 (2006); Solid Waste Agency of Northern Cook County v. U.S. Army Corps of Engineers, 531 U.S. 159 (2001); U.S. v. Riverside Bayview Homes, Inc., 474 U.S. 121 (1985).

63 *See Revised Definition of "Waters of the United States,"* Final Rule, Docket No. EPA–HQ–OW–2021–0602; FRL–6027.4–01–OW, 88 Fed. Reg. 3004 (January 18, 2023)

64 *See id.* at 3005–6.

The scope of the CWA expanded as a result of a decision of the U.S. Supreme Court in *County of Maui v. Hawaii Wildlife Fund*, which held that the discharge of pollutants via groundwater requires a CWA permit.[65] Groundwater is not itself WOTUS. However, if pollutants pass through groundwater from a point source to WOTUS, a permit may be required.[66] The Court held that discharge into groundwater "is the functional equivalent of a direct discharge."[67] The existence of a functional discharge will depend on an analysis including time and distance, and other factors.[68] Additional litigation or administrative action may clarify the functional discharge analysis.[69] *County of Maui* reduces the importance of the precise definition of WOTUS because WOTUS is generally part of the watershed.[70]

Effluents

The EPA regulates under its National Pollutant Discharge Elimination System (NPDES) permitting authority discharges from and intakes to power plants, including water cooling systems at steam electric power generating stations, under the CWA.[71]

Executive Order 13990 called for review and improvement of the existing 2020 Steam Electric Reconsideration Rule. The EPA intends to issue a proposed rule in the fall of 2022 to strengthen certain discharge limits applicable to steam generating units.[72]

On June 9, 2022, the EPA proposed the Water Quality Certification Improvement Rule (WQCIR), which would expand the grounds on which states may condition or block, projects in federal permit proceedings.[73] The WQCIR would provide each state certifying agency a role in determining the "reasonable period of time" to review the request and encourage their adoption of an "activity as a whole" analytical approach that would consider the impacts of the entire project rather than just the specific discharge needing certification.[74]

The EPA is currently implementing its 2015 and 2020 rules.[75] [76] The 2015 Rule established limitations and standards applicable to discharges from steam electric generating units from bottom ash (BA) transport water, flue gas desulfurization (FGD) wastewater, fly ash (FA) transport water, flue gas mercury control wastewater, gasification wastewater, combustion residual leachate, and non chemical metal cleaning wastes. The 2020 Rule revised the limitations and standards for BA transport water and FGD wastewater, leaving the other limitations and standards in place. The 2020 Rule applied less stringent effluent limits to three new subcategories of units: High FGD flow plants, low utilization generating units, and generating units that will permanently cease the combustion of coal by 2028.

Units subject to the generally applicable limits had to comply with the 2020 Rule as soon as possible on or after October 13, 2021, but no later than December 31, 2025.[77] Some owners have already indicated an intent to close generating units based on the discharge limits in the 2020 Rule.

The EPA is now implementing its Effluent Guidelines. The EPA has also proposed to tighten those guidelines.[78] The Effluent Guidelines establish effluent limitations and pretreatment standards applicable to steam electric generating units. Plants are required to inform regulators of their plans to comply with the new rule by upgrading their plants with pollution control equipment or retiring their units by 2028.[79]

65 Slip. Op. No. 18-260 (April 23, 2020).
66 *Id.*
67 *Id.* at 1.
68 *Id.* at 16 ("The difficulty with this approach, we recognize, is that it does not, on its own, clearly explain how to deal with middle instances. But there are too many potentially relevant factors applicable to factually different cases for this Court now to use more specific language. Consider, for example, just some of the factors that may prove relevant (depending upon the circumstances of a particular case): (1) transit time, (2) distance traveled, (3) the nature of the material through which the pollutant travels, (4) the extent to which the pollutant is diluted or chemically changed as it travels, (5) the amount of pollutant entering the navigable waters relative to the amount of the pollutant that leaves the point source, (6) the manner by or area in which the pollutant enters the navigable waters, (7) the degree to which the pollution (at that point) has maintained its specific identity. Time and distance will be the most important factors in most cases, but not necessarily every case.").
69 *Id.*
70 See *id.* at 5 ("Virtually all water, polluted or not, eventually makes its way to navigable water. This is just as true for groundwater.").
71 See 40 CFR Part 423. For more details, see the *2019 State of the Market Report for PJM*, Volume II, Appendix H: "Environmental and Renewable Energy Regulations."
72 See *Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category*, EPA Docket No. FRL 8794-04-OW, 86 Fed. Reg. 41801 (August 3, 2021).
73 See *Clean Water Act Section 401 Water Quality Certification Improvement Rule*, Proposed Rule, 87 Fed. Reg. 35318 (June 9, 2022).
74 *Id.* at 35343–35349.
75 See *Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category*, Docket No. EPA-HQ-OW-2009-0819; FRL-9930-48- OW, 80 Fed. Reg. 67838 (November 3, 2015).
76 See *Steam Electric Reconsideration Rule*, Docket No. EPA-HQ-OW-2009-0819; FRL-10014-41-OW, 85 Fed. Reg. 64650 (October 13, 2020).
77 *Id.* at 64652.
78 See *Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category*, EPA Docket No. FRL 8794-04-OW, 86 Fed. Reg. 41801 (August 3, 2021); *Steam Electric Reconsideration Rule*, Docket No. EPA-HQ-OW-2009-0819; FRL-10014-41-OW, 85 Fed. Reg. 64650 (October 13, 2020); *Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category*, Docket No. EPA-HQ-OW-2009-0819; FRL-9930-48- OW, 80 Fed. Reg. 67838 (November 3, 2015) (collectively "Effluent Guidelines").
79 85 Fed. Reg. 64650, 64679–82.

RCRA: Coal Ash

The EPA administers the Resource Conservation and Recovery Act (RCRA), which governs the disposal of solid and hazardous waste.[80] Solid waste is regulated under subtitle D. Subtitle D criteria are not directly enforced by the EPA. Subtitle C governs the disposal of hazardous waste. Hazardous waste is subject to direct regulatory control by the EPA from the time it is generated until its ultimate disposal.

On April 17 2015, the EPA published a rule under Subtitle D of RCRA, the Coal Combustion Residuals rule (2015 CCRR), which sets criteria for the disposal of coal combustion residues (CCRs), or coal ash, produced by electric utilities and independent power producers.[81] CCRs include fly ash (trapped by air filters), bottom ash (scooped out of boilers) and scrubber sludge (filtered using wet limestone scrubbers). These residues are typically stored on site in ponds (surface impoundments) or sent to landfills.

In 2016, RCRA was amended to establish a permitting scheme allowing states to apply to the EPA for approval to operate a permit program that implements the CCR rule. Such state programs could include alternative state standards, provided that the EPA determines that they are ''at least as protective as'' the EPA CCR regulations.[82]

Effective August 9, 2018, the EPA approved certain revisions to the 2015 CCRR ("2018 CCRR Revisions") partly in response to the 2016 amendments.[83]

The 2018 CCRR Revisions provide for two types of alternative performance standards. The first type of standards allows a state director (if a state has an EPA approved CCR permit program) or the EPA (if no state program) to suspend groundwater monitoring requirements if there is evidence that there is no potential for migration of hazardous constituents to the uppermost aquifer during the active life of the unit and during post closure care. The second type allows issuance of technical certifications by a state director in lieu of a professional engineer.

The 2018 CCRR Revisions revised the groundwater protection standards for health-based levels for four contaminants: cobalt at 6 mg/L; lithium at 40 mg/L; molybdenum at 100 mg/L and lead at 15 mg/L. Standards for other monitored contaminants follow the Maximum Contaminant Level (MCL) established under the Safe Water Drinking Act.

The 2018 CCRR Revisions extended the deadline for closing coal ash units in two situations: (i) detection of a statistically significant increase above a groundwater protection standard from an unlined surface impoundment; or (ii) inability to comply with the location restriction regarding placement above the uppermost aquifer. The exceptions in the 2018 CCRR to the standards in the 2015 CCRR and relaxation of the deadlines create a less stringent federal rule.

The U.S. Court of Appeals for the D.C. Circuit invalidated certain provisions of the 2015 CCRR and remanded it to the EPA.[84]

On July 29, 2020, the EPA finalized revisions to CCRR in compliance with the court orders ("Revised CCRR").[85] The Revised CCRR requires (i) unlined surface impoundments (ponds) and ponds failing restrictions on the minimum depth to or interaction with an aquifer to cease receiving waste as soon as technically feasible and no later than April 11, 2021; and (ii) removal of compacted soil lined and clay lined ponds from classification as lined and exempt from CCRR.[86] Impoundment facilities unable to meet the earliest deadline would be able to obtain extensions until an alternative can be "technically feasibly implemented."[87] Utilities had until November 30, 2020, to obtain an automatic extension upon certification of need for additional time.[88] [89] Upon receipt of required documentation satisfying certain criteria, the EPA could grant certain extensions, including to as late as October 17, 2028, for a facility with

80 42 U.S.C. §§ 6901 *et seq.*

81 *See Hazardous and Solid Waste Management System; Disposal of Coal Combustion Residuals from Electric Utilities*, 80 Fed. Reg. 21302 (April 17, 2015).

82 The Water Infrastructure Improvements for the Nation Act (WIIN Act).

83 See *Hazardous and Solid Waste Management System: Disposal of Coal Combustion Residuals from Electric Utilities; Amendments to the National Minimum Criteria (Phase One, Part One)*, EPA Docket No. EPA-HQ-OLEM-2017-0286, 83 Fed. Reg. 36435 (July 30, 2018).

84 Utility Solid Waste Activities Group, et al. v. EPA, 901 F.3d 414 (D.C. Cir. August 21, 2018); Waterkeeper Alliance Inc. et al. v. EPA, No. 18-1289 (D.C. Cir. March 13, 2019).

85 See *Hazardous and Solid Waste Management System: Disposal of Coal Combustion Residuals From Electric Utilities; A Holistic Approach to Closure Part A: Deadline To Initiate Closure*, EPA-HQ-OLEM-2019-0172; FRL-10002- 02-OLEM, 85 Fed. Reg. 53516 (August 28, 2020).

86 *Id.* at 53516-53517, 53536.

87 *Id.* at 53546; 40 CFR § 257.103(f)(1).

88 *Id.* at 65942.

89 A number of plants in PJM timely filed for extensions.

a surface impoundment of 40 acres or greater that commits to a deadline for ending operations of its boiler.[90]

The EPA has under review 16 completed applications from PJM plants for extensions of the deadline for compliance with the Revised CCRR. The EPA has proposed action on three applications.

On November 18, 2022, the EPA issued a final denial of the application of the General James M. Gavin Plant (2,600 MW) located in the PJM footprint in Cheshire, Ohio (Gavin).[91] The EPA required the Gavin Plant to stop receiving waste at its bottom ash pond no later than April 12, 2023, or such later date as the EPA establishes to address demonstrated electric grid reliability issues.[92] The Gavin Plant has upgraded its facilities and is now in compliance with requirements to close its bottom ash pond, and will continue operating.

On January 11, 2022, the EPA proposed to deny the application of the Clifty Creek Power Plant (1,300 MW) owned by Ohio Valley Electric Corp. (OVEC) and located in the PJM footprint in Madison, Indiana (Clifty Creek).[93] The EPA proposes that both Clifty Creek cease receipt of waste and initiate closure of its surface impoundment no later than 135 days from the date of the EPA's final decision.[94] The EPA provides the potential for an extension for such period that PJM may determine that Clifty Creek is needed for reliability and the EPA agrees is appropriate.[95]

On January 25, 2023, the EPA proposed to deny the application of the Conemaugh Generating Station (1,872 MW) located in the PJM footprint in New Florence, Pennsylvania.[96] The comment period for the proposed denial ended March 10, 2023. The EPA proposes that Conemaugh cease receipt of waste into the Ash Filter Ponds A, B, C, and D and initiate closure no later than 135 days from the date of EPA's final decision (or such later date as EPA determines is necessary to address grid reliability).[97] The EPA provides the potential for an extension for such period that PJM may determine that Conemaugh is needed for reliability and the EPA agrees is appropriate.[98]

In response to the RCRA amendments, the EPA proposed a new rule to implement a federal CCR permit program in non participating states, noticed February 20, 2020.[99] This proposal includes requirements for federal CCR permit applications, content and modification, as well as procedural requirements. The EPA would implement this permit program at CCR units located in states that have not submitted their own CCR permit program for approval. No PJM state has yet applied for EPA approval of its own CCR permit program.

State Environmental Regulation

State Coal Ash Regulations

In Virginia, the Waste Management Board amended the Virginia Solid Waste Management Regulations in December 2015, to incorporate the EPA's 2015 CCRR, and did not adopt the less stringent 2018 CCRR Revisions. On July 1, 2019, Virginia enacted legislation directing the closure of coal ash ponds located in the Chesapeake Bay Watershed and owned by Dominion Energy.[100] Dominion is currently developing plans to remove coal ash ponds at power stations in the Chesapeake Bay Watershed. The removed coal ash must be recycled (at least 6.8 million cubic yards) or disposed of in a modern, lined landfill. The Virginia DEQ is addressing closing ash ponds under two types of environmental permits: wastewater discharge permits covering the removal of treated water from the ponds; or solid waste permits covering the permanent closure of the ponds.

Table 8-2 shows the compliance status of affected units with Virginia Solid Waste Management Regulations:[101]

90 *Id.*
91 Denial of Alternative Closure Deadline for General James M. Gavin Plant, Cheshire, Ohio, Docket No.: EPA-HQ-OLEM-2021-0590 (November 18, 2022) ("Gavin Denial Order").
92 87 Fed. Reg. 72989 (November 28, 2022).
93 Proposed Denial of Alternative Closure Deadline for Clifty Creek Power Station, Proposed Decision, Docket No. EPA-HQ-OLEM-2021-0587 (January 11, 2022) ("Clifty Creek Proposed Denial Order").
94 Clifty Creek Proposed Denial Order at 77.
95 Clifty Creek Proposed Denial Order at 76-77.
96 Proposed Denial of Alternate Liner Demonstration Application for Conemaugh Generating Station, New Florence, Pennsylvania, Docket No. EPA-HQ-OLEM-2021-0281 (January 25, 2023}) ("Conemaugh Proposed Denial Order").
97 Conemaugh Proposed Denial Order at 50.
98 Conemaugh Proposed Denial Order at 49-50.
99 *See Hazardous and Solid Waste Management System: Disposal of Coal Combustion Residuals from Electric Utilities; Federal CCR Permit Program*, EPA-HQ-OLEM-2019-0361, FRL-10003-82-OLEM, 85 Fed. Reg. 9940 (February 20, 2020).
100 Va. Code § 10.1-1402.03.
101 Virginia Department of Environmental Quality website: https://www.deq.virginia.gov/permits-regulations/permits/waste/coal.

Table 8-2 Compliance status of affected units with Virginia Solid Waste Management Regulations

Plant	CCR Compliance Status
Bremo Bluff Power Station	As of April 2020, ash has been removed from the East and West Ponds. Plans for closure by removal of ash from the remaining North Pond impoundment are under development and will be addressed by the Virginia DEQ in a separate future permitting action.
Chesapeake Energy Center	The facility is currently developing plans for closure by removal of ash from the landfill, historical area, and impoundment.
Chesterfield Power Station	Dominion Energy Virginia submitted the required solid waste permit application for closure by removal and groundwater monitoring of the Upper and Lower Ash Ponds in February 2020, and it is currently under review. The application outlines the removal of ash to either an offsite permitted landfill or offsite beneficial reuse. The application estimates that it will take approximately 13 years to complete closure by removal activities.
Clinch River Power Station	The ash pond was closed and capped prior to January 1, 2019. Clinch River Plant ceased burning coal in 2015 and no longer produces CCR material. The Plant now uses natural gas as fuel. All units are currently being monitored and maintained in post-closure care.
Clover Power Station	The station also has had a permitted CCR landfill since 1993. The permit is currently under revision to incorporate EPA CCR Rule requirements applicable to existing landfills.
Possum Point	As of June 2019, ash has been removed from Ponds A, B, C, and E. Plans for closure by removal of ash from the remaining impoundment (Pond D) are under development. Closure by removal of Pond D will be addressed in a future and separate DEQ permitting action.

Effective April 21, 2021, in response to a statutory mandate,[102] the Illinois Environmental Protection Agency (Illinois EPA) promulgated rules for coal combustion residual surface impoundments with the Illinois Pollution Control Board.[103] The proposed rules contain standards for the storage and disposal of coal combustion residuals in surface impoundments. The rules include a permitting program intended to meet federal standards.[104] The Illinois EPA identified 73 coal combustion residuals surface impoundments at power stations, some lined with impermeable materials and some not.[105] The Illinois EPA believes that as many as six lined surface impoundments may comply with the federal liner standards.[106]

The North Carolina Department of Environmental Quality (NCDEQ) has initiated a rule making on rules for the disposal or recycling of coal combustion residuals. None of the affected power stations or power station impoundments are located in the PJM Dominion Zone (which includes a portion of northeast coastal North Carolina).

The Maryland Department of Environment (MDE) indicated in April 2020, that it would require GenOn Holdings Inc. to meet a November 1, 2020, deadline for compliance with effluent guidelines at Chalk Point Generating Station, Dickerson Generating Station and Morgantown Generating Station.[107] On May 15, 2020, GenOn announced its decision to retire the Dickerson Generating Station.[108] Dickerson Generating Station was retired effective August 13, 2020. The Chalk Point coal units were retired effective June 1, 2021. On June 9, 2021, GenOn reported that it would retire its Morgantown coal fired unit by May 31, 2022, five years earlier than previously announced.[109]

State Emissions Regulations

States have in some cases enacted emissions regulations more stringent or potentially more stringent than federal requirements:[110]

- **Illinois Climate and Equitable Jobs Act (CEJA).** On September 16, 2021, Illinois Governor J.B. Pritzker signed the Climate and Equitable Jobs Act (CEJA). CEJA created an expanded nuclear subsidy program. CEJA mandates that all fossil fuel plants close by 2045. CEJA established emissions caps for investor owned, gas-fired units with three years of operating history, effective October 1, 2021, on a rolling 12 month

102 Ill. Public Act 101-171 (a.k.a. SB 09).
103 The proposed rule amends the Illinois Administrative Code to create a new Part 845 in Title 35.
104 See *In the Matter of Standards for the Disposal of Coal Combustion Residuals in Surface Impoundments*, No. R 2020-019 (March 30, 2020) at 1 (Proposed New 35 Ill. Adm. Code 845).
105 In the Matter of Standards for the Disposal of Coal Combustion Residuals in Surface Impoundments, No. R 2020-019 (March 30, 2020) at 3 (Proposed New 35 Ill. Adm. Code 845z0.
106 *Id.*

107 See Potomac Riverkeeper Network, Press Release, "Maryland Proposes to Reject Effort to Delay Pollution Reductions" (Posted April 4, 2020), <https://www.potomacriverkeepernetwork.org/maryland-proposes-to-reject-effort-to-delay-pollution-reductions/>.
108 See "GenOn Holdings, Inc. Announces Retirement of Dickerson Coal Plant" (May 15, 2020) <https://www.genon.com/genon-news/genon-holdings-inc-announces-retirement-of-dickerson-coal-plant>.
109 See "GenOn Holdings, LLC Announces Retirement of Three Coal-Fired Power Plants" (June 9, 2021) <https://www.genon.com/genon-news/genon-holdings-llc-announces-retirement-of-three-coal-fired-power-plants>.
110 For more details, see the *2019 State of the Market Report for PJM*, Volume 2, Appendix H: "Environmental and Renewable Energy Regulations."

basis.[111] [112] The emissions caps are based on average emissions over a three year period from 2018 through 2020. The capped emissions are CO2e and co-pollutants.[113] [114] New investor owned, gas-fired units will have emissions caps after three years of operation. The resultant emissions caps are very low for some units and higher for others. More than 10,000 MW of capacity are currently affected, most of which have requested that the MMU calculate a unit specific opportunity cost. The MMU calculates opportunity costs for units that make requests and provide required data.

The CEJA includes provisions promoting the development of batteries and utility scale solar at the sites of up to five closed coal plants, two of which may be located in PJM. CEJA grants a subsidy of $110,000/MW for battery projects with at least 37 MW of capacity, capped at $28 million per year. A solar resource at a defined site may elect to receive either the battery subsidies or to sell premium RECs for $30 each.

- **New Jersey HEDD.** Units that run only during peak demand periods have relatively low annual emissions, and have less reason to make such investments under the EPA transport rules. New Jersey addressed the issue of NO_X emissions on peak energy demand days with a rule that defines peak energy usage days, referred to as high electric demand days or HEDD, and imposes operational restrictions and emissions control requirements on units responsible for significant NO_X emissions on such high energy demand days. New Jersey's HEDD rule, which became effective May 19, 2009, applies to HEDD units, which include units that have a NO_X emissions rate on HEDD equal to or exceeding 0.15 lbs/MMBtu and lack identified emission control technologies.

111 Letter of John J. Kim, Director, Illinois Environmental Protection Agency, to Dr. Joseph Bowring, Market Monitor (January 21, 2022) ("IEPA January 21st Letter") <https://www.monitoringanalytics.com/reports/Market_Messages/Messages/IL_EPA_CEJA_Response_to_the_IMM_20220121.pdf>.

112 The IEPA January 21st Letter explains: "All of this information is already reported to USEPA by sources subject to Section k-5, per 40 CFR Part 98, and Illinois does not intend for any changes in existing methodologies in that regard. Specifically, Part 98.2(a)(1) requires Part 98 reporting of sources that are subject to Part 75. CO2e emissions are calculated using Equation A-1 from 40 CFR 98.2(b)(4), and emissions data for specific contributing pollutants are taken from a combination of CEMS data and other measurement or estimation methods. Part 98.3 requires reporting of CO2, CH4, N2O, and each fluorinated GHG. This covers all pollutants used to calculate CO2e that would be emitted by sources subject to Section k-5. Part 75.13 requires use of CO2 CEMS or alternate methods that are acceptable continuous monitoring methods detailed in Appendices F and G to Part 75. Part 98 Tables C-1 and C-2 have default values for CH4, N2O, and other GHGs, based on fuel type, that sources should continue to use for requirements pursuant to Section k-5; they are essentially considered to be continuous parameter monitoring based on fuel consumption."

113 Carbon dioxide equivalent (CO2e) emissions means the total emissions of six greenhouse gases (carbon dioxide, nitrous oxide, methane, hydrofluorocarbons, perfluorocarbons and sulfur hexafluoride). Co-pollutants mean the six criteria pollutants identified by the US EPA pursuant to the Clean Air Act: Carbon Monoxide, Lead, Nitrogen Dioxide, Ozone, Particle Pollution, and Sulfur Dioxide.

114 See Energy Transition Act, Public Act 102-0662, Section 90-55, which amends section 9.15 (k-5) FOR the Illinois Environmental Protection Act.

- **New Jersey Control and Prohibition of Carbon Dioxide Emissions.** On December 2, 2022, New Jersey implemented rules restricting new power plants to CO_2 emissions less 860 pounds per megawatt hour, and banning sales of No. 4 and No. 6 fuel oil.[115] The rule limits existing electric generating units to no more than 1,700 lbs of CO_2 per megawatt hour of the gross energy input, by January 1, 2024, to no more than 1,300 pounds per megawatt hour by 2027, and to no more than 1,000 power per megawatt hour by 2035.
- **Climate Solutions Now Act of 2022.** One April 8, 2022, Maryland enacted a requirement for reduction of statewide greenhouse gas emissions by 60 percent from 2006 levels by 2031 and net-zero emissions by 2045.[116]
- **Illinois Air Quality Standards (NO_X, SO_2 and Hg).** The State of Illinois has promulgated its own standards for NO_X, SO_2 and Hg (mercury) known as Multi-Pollutant Standards (MPS) and Combined Pollutants Standards (CPS). MPS and CPS establish standards that are more stringent and take effect earlier than comparable Federal regulations, such as the EPA's MATS.

Some states have enacted legislation in 2022 or have pending legislation in 2022 designed to reduce or eliminate greenhouse gas and other emissions, summarized in Table 8-3.

115 See N.J.A.C. 7:27F.

116 See Maryland SB 528.

Table 8-3 Summary of environmental regulatory activity impacting PJM resources by jurisdiction

Jurisdiction	Bill/Docket No.	Environmental Regulatory Activity
Delaware		No current activity.
Illinois	HB 2178	2023-2024, 103rd General Assembly: Repeals the Energy Transition Act, the Energy Community Reinvestment Act, the Community Energy, Climate, and Jobs Planning Act, and the Illinois Clean Energy Jobs and Justice Fund Act.
Indiana		No current activity.
Kentucky		No current activity.
Maryland		No current activity.
Michigan		No current activity.
New Jersey	AB 3079	2022-2023 Reg. Sess.: Requires, by energy year 2050, all electric power sold in NJ by each electric power supplier and basic generation service provider to be from zero-carbon sources.
	SB 2185	2022-2023 Reg. Sess.: Requires BPU to develop program to incentivize installation of new energy storage systems.
	SB 1170/AB 1440	2022-2023 Reg. Sess.: Requires that all new residential and commercial developments be zero energy ready and that developers to offer zero energy construction.
	AB 1744	2022-2023 Reg. Sess.: Revises law concerning Class I and solar renewable energy portfolio standards, solar renewable energy certificates, and net metering.
	SCR 17	2022-2023 Reg. Sess.: Amends Constitution to prohibit construction of new fossil fuel power plants.
	SB 1384	2022-2023 Reg. Sess.: Establishes Nuclear Power Advisory Commission.
	AB 4782	2022-2023 Reg. Sess.: Increases the goal for the annual capacity of solar energy projects to be developed under the permanent Community Solar Energy Program from 50 to 500 megawatts per year.
	AB 4658	2022-2023 Reg. Sess.: Revises State renewable energy portfolio standards.
North Carolina		No current activity.
Ohio		No current activity.
Pennsylvania		No current activity.
Tennessee		No current activity.
Virginia	HB 2197	2023, Regular Session: Virginia Electric Utility Regulation Act: renewable energy; eligible sources for renewable energy portfolio standard program. Provides that for the purpose of the Virginia Electric Utility Regulation Act, renewable energy includes energy from advanced nuclear technology or hydrogen. The bill classifies electric-generating resources that generate electric energy derived from advanced nuclear technology or hydrogen located in the Commonwealth or physically located within the PJM region as renewable energy portfolio standard program sources.
	HB 2311	2023, Regular Session: Virginia Electric Utility Regulation Act; renewable energy; eligible sources for renewable energy portfolio standard program. Provides that for the purpose of the Virginia Electric Utility Regulation Act, renewable energy includes energy from nuclear and hydrogen power. The bill provides electric-generating resources that generate electric energy derived from nuclear or hydrogen power located in the Commonwealth or physically located within the PJM region as a renewable energy portfolio standard program source.
	HB 1670	2023, Regular Session: Virginia Electric Utility Regulation Act. Provides that, in lieu of the triennial review proceedings required under current law, Dominion Energy Virginia, beginning in 2023, will be subject to biennial reviews of their rates, terms, and conditions for generation, distribution, and transmission services. The bill also prohibits an investor-owned incumbent electric utility from permanently retiring an electric power generation facility from service after July 1, 2023, without first obtaining the approval of the Commission and a finding by the Commission that the retirement determination, after consideration of the impact of the proposed retirement on reliability or security of electric service to customers, is reasonable and prudent. Such prohibition does not apply to early retirement determinations identified by the utility in an integrated resource plan filed with the Commission by July 1, 2023. Virginia Electric Utility Regulation Act. Provides that, in lieu of the triennial review proceedings required under current law, Dominion Energy Virginia, beginning in 2023, will be subject to biennial reviews of their rates, terms, and conditions for generation, distribution, and transmission services. The bill also prohibits an investor-owned incumbent electric utility from permanently retiring an electric power generation facility from service after July 1, 2023, without first obtaining the approval of the Commission and a finding by the Commission that the retirement determination, after consideration of the impact of the proposed retirement on reliability or security of electric service to customers, is reasonable and prudent. Such prohibition does not apply to early retirement determinations identified by the utility in an integrated resource plan filed with the Commission by July 1, 2023.
	HB 2444/SB 1441	2023, Regular Session: Requires the VSCC, in conducting its review of requests for cost recovery by a Phase II Utility for costs associated with generating facilities utilizing energy derived from offshore wind, to give due consideration to the economic development benefits.
Washington, D.C.		No current activity.
West Virginia	HB 2175	2023, Regular Session: The purpose of this bill is to limit the number of permits to construct wind power plants, wind power farms, or "windmills" for power generally in West Virginia; to provide that for each new wind powered facility built in West Virginia, there is an offset in the amount of taxes paid by new and existing coal fired power plants; and to ensure that coal remains the primary source of power in West Virginia during emergency weather events.

Clean Energy Standards

In April 2020, Virginia enacted the Virginia Clean Economy Act, which orders the closure of most coal generation in state by 2024, most fossil fuel generation by 2045, and adopts a 100 percent clean energy standard by 2045.[117] The legislation mandates Chesterfield Power Station Units 5 & 6 and Yorktown Power Station Unit 3 to be retired by the end of 2024, Altavista, Southampton and Hopewell to be retired by the end of 2028 and Virginia Power's remaining fossil fuel units to be retired by the end of 2045, unless the retirement of such generating units will compromise grid reliability or security.[118] The legislation also imposes a temporary moratorium on Certificates of Public Convenience and Necessity for fossil fuel generation, unless the resources are needed for grid reliability.[119]

RGGI

The Regional Greenhouse Gas Initiative (RGGI) is a cooperative effort by Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New Jersey (as of January 1, 2020), New York, Rhode Island, Vermont and Virginia (as of January 1, 2021) to cap CO_2 emissions from power generation facilities.[120]

Delaware, Maryland, New Jersey, and Virginia are members of RGGI. New Jersey, a founding member of RGGI, opted out in 2011 but rejoined RGGI in 2020.[121] Virginia joined RGGI on January 1, 2021. Pennsylvania took action to join RGGI on April 23, 2022, but such action has been enjoined by court order on appeal.[122] [123] A decision on the merits of the appeal is pending at the Supreme Court of Pennsylvania.

Table 8-4 shows the RGGI CO_2 auction clearing prices and quantities, in short tons and metric tonnes, for the 3rd control period, the 4th control period, and the first nine auctions of the 5th control period.[124] [125] The clearing price for the auction held March 8, 2023 was $12.50 per allowance (equal to one short ton of CO_2).[126] The March auction clearing price decreased 3.8 percent from the last auction clearing price of $12.99 in December 2022.

117 Va. HB 1526/SB 851.
118 See Dominion Energy, Inc., et al., SEC Form 10-Q (Quarter ending June 30, 2020).
119 *Id.*
120 RGGI provides a link on its website to state statutes and regulations authorizing its activities, which can be accessed at: <http://www.rggi.org/design/regulations>.
121 "Statement on New Jersey Greenhouse Gas Rule," RGGI Inc., (June 17, 2019) <https://www.rggi.org/sites/default/files/Uploads/Press-Releases/2019_06_17_NJ_Announcement_Release.pdf>.
122 CO2 Budget Trading Program, 52 Pa.B. 2471 (April 23, 2022), codified 25 Pa. Code Ch. 145; *see also* Executive Order–2019-07. Commonwealth Leadership in Addressing Climate Change through Electric Sector Emissions Reductions, Tom Wolf, Governor, October 3, 2019, <https://www.governor.pa.gov/newsroom/executive-order-2019-07-commonwealth-leadership-in-addressing-climate-change-through-electric-sector-emissions-reductions/>.
123 See *Ramez Ziadeh, et al. v. Pennsylvania Legislative Reference Bureau*, Memorandum Opinion, Commonwealth Court of Pennsylvania Case No. No. 41 M.D. 2022 (July 8, 2022); *Ramez Ziadeh, et al. v. Pennsylvania Legislative Reference* Bureau, Order Granting Application to Vacate, Commonwealth Court of Pennsylvania Case No. No. 41 M.D. 2022 (July 25, 2022).
124 Each control period is three years in duration. The 3rd control period covers 2015 through 2017. The 4th control period covers 2018 through 2020. The 5th control period covers 2021 through 2023.
125 The December 2021 auction included additional Cost Containment Reserves (CCRs) since the clearing price for allowances was above the CCR trigger price of $13.00 per ton. The auctions on March 5, 2014, September 3, 2015, and December 1, 2021 are the only auctions that included CRRs.
126 RGGI measures carbon in short tons (short ton equals 2,000 pounds) while world carbon markets measure carbon in metric tonnes (metric tonne equals 1,000 kilograms or 2,204.6 pounds).

Table 8-4 RGGI CO_2 allowance auction prices and quantities in short tons and metric tonnes: 3rd, 4th and 5th Control Periods[127]

	Short Tons				Metric Tonnes			
Auction Date	Clearing Price	Quantity Offered	Cost Containment Reserve	Quantity Sold	Clearing Price	Quantity Offered	Cost Containment Reserve	Quantity Sold
March 11, 2015	$5.41	15,272,670		15,272,670	$5.96	13,855,137		13,855,137
June 3, 2015	$5.50	15,507,571		15,507,571	$6.06	14,068,236		14,068,236
September 9, 2015	$6.02	15,374,294	10,000,000	25,374,294	$6.64	13,947,329	9,071,850	23,019,179
December 2, 2015	$7.50	15,374,274		15,374,274	$8.27	13,947,311		13,947,311
March 9, 2016	$5.25	14,838,732		14,838,732	$5.79	13,461,475		13,461,475
June 1, 2016	$4.53	15,089,652		15,089,652	$4.99	13,689,106		13,689,106
September 7, 2016	$4.54	14,911,315		14,911,315	$5.00	13,527,321		13,527,321
December 7, 2016	$3.55	14,791,315		14,791,315	$3.91	13,418,459		13,418,459
March 8, 2017	$3.00	14,371,300		14,371,300	$3.31	13,037,428		13,037,428
June 7, 2017	$2.53	14,597,470		14,597,470	$2.79	13,242,606		13,242,606
September 8, 2017	$4.35	14,371,585		14,371,585	$4.80	13,037,686		13,037,686
December 8, 2017	$3.80	14,687,989		14,687,989	$4.19	13,324,723		13,324,723
March 14, 2018	$3.79	13,553,767		13,553,767	$4.18	12,295,774		12,295,774
June 13, 2018	$4.02	13,771,025		13,771,025	$4.43	12,492,867		12,492,867
September 9, 2018	$4.50	13,590,107		13,590,107	$4.96	12,328,741		12,328,741
December 5, 2018	$5.35	13,360,649		13,360,649	$5.90	12,120,580		12,120,580
March 13, 2019	$5.27	12,883,436		12,883,436	$5.81	11,687,660		11,687,660
June 5, 2019	$5.62	13,221,453		13,221,453	$6.19	11,994,304		11,994,304
September 4, 2019	$5.20	13,116,447		13,116,447	$5.73	11,899,044		11,899,044
December 4, 2019	$5.61	13,116,444		13,116,444	$6.18	11,899,041		11,899,041
March 11, 2020	$5.65	16,208,347		16,208,347	$6.23	14,703,969		14,703,969
June 3, 2020	$5.75	16,336,298		16,336,298	$6.34	14,820,045		14,820,045
September 2, 2020	$6.82	16,192,785		16,192,785	$7.52	14,689,852		14,689,852
December 2, 2020	$7.41	16,237,495		16,237,495	$8.17	14,730,412		14,730,412
March 3, 2021	$7.60	23,467,261		23,467,261	$8.38	21,289,147		21,289,147
June 2, 2021	$7.97	22,987,719		22,987,719	$8.79	20,854,114		20,854,114
September 8, 2021	$9.30	22,911,423		22,911,423	$10.25	20,784,899		20,784,899
December 1, 2021	$13.00	23,121,518	3,919,482	27,041,000	$14.33	20,975,494	3,555,695	24,531,190
March 9, 2022	$13.50	21,761,269		21,761,269	$14.88	19,741,497		19,741,497
June 1, 2022	$13.90	22,280,473		22,280,473	$15.32	20,212,511		20,212,511
September 7, 2022	$13.45	22,404,023		22,404,023	$14.83	20,324,594		20,324,594
December 7, 2022	$12.99	22,233,203		22,233,203	$14.32	20,169,628		20,169,628
March 8, 2023	$12.50	21,522,877		21,522,877	$13.78	19,525,231		19,525,231

The RGGI auction held on March 8, 2023, generated $269.0 million in auction revenue. RGGI auctions have generated $6.2 billion in auction revenue since 2008.[128] RGGI auction revenue is returned to the states. RGGI reported that the RGGI states, cumulative through the 2020 reporting year, have invested $3.0 billion, 79.0 percent of revenues auction revenues.[129] The $3.0 billion of investment includes 53 percent on energy efficiency, 14 percent on clean and renewable energy, 8 percent on greenhouse gas abatement, 16 percent on direct bill assistance, 3 percent on beneficial electrification, 6 percent on administration and 1 percent on RGGI, Inc.[130]

If all PJM states joined RGGI, the total RGGI revenue to the PJM states would be significant. The estimated allowance revenue for PJM states based on 2021 CO_2 emission levels and the RGGI clearing price for the March 2023 auction ranges from $1.9 billion per year to $3.5 billion per year depending on associated reductions in carbon emission levels (Table 8-5).[131] Table 8-5 shows the estimated carbon allowance revenue for each PJM state based on the latest RGGI auction price and reductions below 2021 CO_2 emission levels ranging from five to 50 percent. A power plant owner must acquire an allowance for each ton of CO_2 emissions and the revenue values in Table 8-5 are computed by multiplying the carbon price by the emission cap level which is expressed as a reduction below the 2021 actual emissions level. States that participate in RGGI choose their emission cap. For example, New Jersey chose an emission cap of 18,000,000 short tons for reentry into RGGI in 2020, 5.3 percent below New Jersey's 2018 CO_2 emissions level; the New Jersey emission cap will be reduced by 540,000 short tons each year through 2030.[132]

127 See Regional Greenhouse Gas Initiative, "Auction Results," <https://www.rggi.org/auctions/auction-results> (Accessed October 17, 2022).
128 See Auction Results at <https://www.rggi.org/>.
129 *The Investment of RGGI Proceeds in 2020*, The Regional Greenhouse Gas Initiative (RGGI) at 14, May 2022, <https://www.rggi.org/investments/proceeds-investments>.
130 *Id.* at 13.
131 This assumes that the PJM states would implement their RGGI rules consistent with the current RGGI states where owners of fossil fuel generators are required to purchase emission allowances in a regional centralized auction or purchase allowances in a secondary market.
132 "Governor Murphy Announces Adoption of Rules Returning New Jersey to Regional Greenhouse Gas Initiative," State of New Jersey, Governor Phil Murphy Press Release, June 17, 2019 <https://nj.gov/governor/news/news/562019/approved/20190617a.shtml>.

Table 8-5 Estimated CO_2 allowance revenue at March 2023 RGGI price level[133 134]

	Estimated CO_2 allowance revenue ($ millions), carbon price $12.50 per short ton						
Jurisdiction	2021 power generation CO_2 emissions (short tons)	5 percent reduction below 2021 emission levels	10 percent reduction below 2021 emission levels	15 percent reduction below 2021 emission levels	20 percent reduction below 2021 emission levels	25 percent reduction below 2021 emission levels	50 percent reduction below 2021 emission levels
Delaware	1,569,515.5	$18.6	$17.7	$16.7	$15.7	$14.7	$9.8
Illinois	20,545,590.8	$244.0	$231.1	$218.3	$205.5	$192.6	$128.4
Indiana	27,066,021.8	$321.4	$304.5	$287.6	$270.7	$253.7	$169.2
Kentucky	23,972,416.9	$284.7	$269.7	$254.7	$239.7	$224.7	$149.8
Maryland	10,527,468.1	$125.0	$118.4	$111.9	$105.3	$98.7	$65.8
Michigan	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
New Jersey	8,424,107.9	$100.0	$94.8	$89.5	$84.2	$79.0	$52.7
North Carolina	61,960.5	$0.7	$0.7	$0.7	$0.6	$0.6	$0.4
Ohio	62,670,551.1	$744.2	$705.0	$665.9	$626.7	$587.5	$391.7
Pennsylvania	67,579,691.3	$802.5	$760.3	$718.0	$675.8	$633.6	$422.4
Tennessee	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Virginia	22,491,149.9	$267.1	$253.0	$239.0	$224.9	$210.9	$140.6
Washington, D.C.	0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
West Virginia	51,728,460.2	$614.3	$581.9	$549.6	$517.3	$485.0	$323.3
Total	296,636,934.0	$3,522.6	$3,337.2	$3,151.8	$2,966.4	$2,781.0	$1,854.0

The RGGI emissions cap is the sum of CO_2 allowances issued by each state. Table 8-6 shows the RGGI emission cap history. Compliance with the RGGI allowance obligation is evaluated at the end of each three year period which is called the control period. The first control period began in 2009. The 2023 compliance year is the third year of the fifth control period.

In 2021, RGGI announced a third adjustment to the RGGI emissions cap to account for banked allowances from previous control periods.[135 136] The first adjustment removed 57.5 allowances that were banked or unused from the first control period. The reduction to the RGGI emissions cap was spread over a seven year period beginning in 2014 and ending with 2020.[137] A second cap adjustment, corresponding to banked allowances for 2012 and 2013, began in 2015 with an adjustment of 13.7 million allowances per year and was in place through 2020.[138] The third adjustment of 95.5 million allowances will be spread over a five year period beginning in 2021.[139] The base emissions cap for each of the next five years will be reduced by 19.1 million allowances. The percent change columns in Table 8-6 show the year to year percent changes in the base RGGI cap and the adjusted RGGI cap.[140] The adjusted emissions cap for 2021 is the only year for which the adjusted carbon emissions cap increased.[141] Figure 8-2 shows the adjusted carbon budgets for the RGGI states. The RGGI clearing price since 2014 has been on average 194.7 percent higher than the prices prior to the emission cap adjustments.

133 The 2020 CO_2 emissions data is from the EPA Continuous Emission Monitoring System (CEMS) from generators located within the PJM footprint.

134 Power generation companies subject to a RGGI emission cap can offset up to 3.3 percent of their allowance obligation by undertaking certain greenhouse gas emission reduction projects. The allowance revenue values in Table 8-3 do not reflect offset allowances.

135 "Third Adjustment for Banked Allowances Announcement," Regional Greenhouse Gas Initiative (March 15, 2021) <https://www.rggi.org/news-releases/rggi-releases>.

136 A banked allowance is an allowance acquired during a previous control period that was not used to fulfill a RGGI allowance obligation.

137 "Second Control Period Interim Adjustment for Banked Allowances Announcement," Regional Greenhouse Gas Initiative (March 17, 2014) at 2. Due to rounding, the adjustment is 8,207,664 allowances for years 2014 through 2018, and 8,207,663 allowances for the remaining two years <https://www.rggi.org/sites/default/files/Uploads/Design-Archive/2012-Review/Adjustments/2014_03_17_SCP_Adjustment.pdf>.

138 Id.

139 "Third Adjustment for Banked Allowances Announcement," Regional Greenhouse Gas Initiative (March 15, 2021) <https://www.rggi.org/news-releases/rggi-releases>.

140 Percent changes for years with membership changes do not reflect the impacts of the change in membership. For example, the RGGI cap for 2020 reflects the impact of New Jersey rejoining RGGI in 2020 but the percent change from 2019 to 2020 does not include New Jersey's allowance budget. Virginia's adoption of RGGI in 2021 is treated analogously.

141 The increase of 4.5 percent does not reflect the addition of Virginia as a RGGI state.

Table 8-6 RGGI emissions cap history[142 143 144]

	Control Period	RGGI Average Clearing Price ($ per short ton)	RGGI Cap (short tons)	Percent Change	RGGI Adjusted Cap (short tons)	Percent Change
2009		$2.77	188,076,976		188,076,976	
2010	1st	$1.93	188,076,976	0.0%	188,076,976	0.0%
2011		$1.89	188,076,976	0.0%	188,076,976	0.0%
2012		$1.93	165,184,246	0.0%	165,184,246	0.0%
2013	2nd	$2.92	165,184,246	0.0%	165,184,246	0.0%
2014		$4.72	91,000,000	(44.9%)	82,792,336	(49.9%)
2015		$6.10	88,725,000	(2.5%)	66,833,592	(19.3%)
2016	3rd	$4.47	86,506,875	(2.5%)	64,615,467	(3.3%)
2017		$3.42	84,344,203	(2.5%)	62,452,795	(3.3%)
2018		$4.41	82,235,598	(2.5%)	60,344,190	(3.4%)
2019	4th	$5.43	80,363,945	(2.3%)	58,472,538	(3.1%)
2020		$6.41	96,354,847	(2.5%)	74,463,439	(3.4%)
2021		$9.61	119,767,784	(3.9%)	100,677,454	4.5%
2022	5th	$13.46	116,112,784	(3.1%)	97,022,454	(3.6%)
2023		$12.50	112,457,784	(3.1%)	93,367,454	(3.8%)

Figure 8-2 RGGI adjusted carbon budgets by state[145]

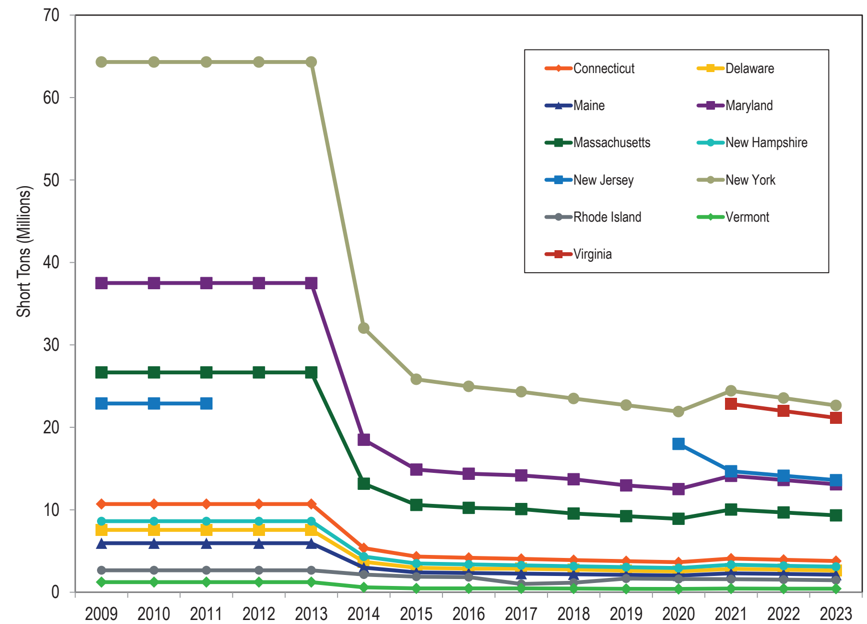


Table 8-7 shows the estimated allowance revenue for PJM states for carbon prices ranging from $10 per short ton to $50 per short ton and for emissions reductions ranging from five percent to 50 percent. Allowance revenues to states would be $14.1 billion if the carbon price were $50 per short ton and emission levels were five percent below 2021 levels. Allowance revenues to states would be $1.5 billion if the carbon price were $10 per short ton and emission levels were 50 percent below 2021.

142 See Regional Greenhouse Gas Initiative, "Allowance Distribution" <https://www.rggi.org/allowance-tracking/allowance-distribution> (Accessed, October 18, 2022).

143 RGGI budgets for 2022 and 2023 are found in a RGGI press release, "Third Adjustment for Banked Allowances Announcement," March 15, 2021 <https://www.rggi.org/news-releases/rggi-releases>.

144 The increase in the RGGI Cap and the RGGI Adjusted Cap in 2020 is due to the reentry of New Jersey. The new cap is 18 million short tons higher than the previously published 2020 caps.

145 Data for the figure was collected from allowance distribution reports available on the RGGI website <https://www.rggi.org/allowance-tracking/allowance-distribution> (Accessed October 18, 2022).

Table 8-7 Estimated CO_2 allowance revenue at various carbon prices

	Estimated CO_2 allowance revenue ($ millions)					
	5 percent reduction below 2021 emission levels	10 percent reduction below 2021 emission levels	15 percent reduction below 2021 emission levels	20 percent reduction below 2021 emission levels	25 percent reduction below 2021 emission levels	50 percent reduction below 2021 emission levels
Jurisdiction		Carbon Price ($ per short ton)			$10.00	
Delaware	$14.9	$14.1	$13.3	$12.6	$11.8	$7.8
Illinois	$195.2	$184.9	$174.6	$164.4	$154.1	$102.7
Indiana	$257.1	$243.6	$230.1	$216.5	$203.0	$135.3
Kentucky	$227.7	$215.8	$203.8	$191.8	$179.8	$119.9
Maryland	$100.0	$94.7	$89.5	$84.2	$79.0	$52.6
Michigan	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
New Jersey	$80.0	$75.8	$71.6	$67.4	$63.2	$42.1
North Carolina	$0.6	$0.6	$0.5	$0.5	$0.5	$0.3
Ohio	$595.4	$564.0	$532.7	$501.4	$470.0	$313.4
Pennsylvania	$642.0	$608.2	$574.4	$540.6	$506.8	$337.9
Tennessee	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Virginia	$213.7	$202.4	$191.2	$179.9	$168.7	$112.5
Washington, D.C.	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
West Virginia	$491.4	$465.6	$439.7	$413.8	$388.0	$258.6
Total	$2,818.1	$2,669.7	$2,521.4	$2,373.1	$2,224.8	$1,483.2
		Carbon Price ($ per short ton)			$25.00	
Delaware	$37.3	$35.3	$33.4	$31.4	$29.4	$19.6
Illinois	$488.0	$462.3	$436.6	$410.9	$385.2	$256.8
Indiana	$642.8	$609.0	$575.2	$541.3	$507.5	$338.3
Kentucky	$569.3	$539.4	$509.4	$479.4	$449.5	$299.7
Maryland	$250.0	$236.9	$223.7	$210.5	$197.4	$131.6
Michigan	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
New Jersey	$200.1	$189.5	$179.0	$168.5	$158.0	$105.3
North Carolina	$1.5	$1.4	$1.3	$1.2	$1.2	$0.8
Ohio	$1,488.4	$1,410.1	$1,331.7	$1,253.4	$1,175.1	$783.4
Pennsylvania	$1,605.0	$1,520.5	$1,436.1	$1,351.6	$1,267.1	$844.7
Tennessee	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Virginia	$534.2	$506.1	$477.9	$449.8	$421.7	$281.1
Washington, D.C.	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
West Virginia	$1,228.6	$1,163.9	$1,099.2	$1,034.6	$969.9	$646.6
Total	$7,045.1	$6,674.3	$6,303.5	$5,932.7	$5,561.9	$3,708.0
		Carbon Price ($ per short ton)			$50.00	
Delaware	$74.6	$70.6	$66.7	$62.8	$58.9	$39.2
Illinois	$975.9	$924.6	$873.2	$821.8	$770.5	$513.6
Indiana	$1,285.6	$1,218.0	$1,150.3	$1,082.6	$1,015.0	$676.7
Kentucky	$1,138.7	$1,078.8	$1,018.8	$958.9	$899.0	$599.3
Maryland	$500.1	$473.7	$447.4	$421.1	$394.8	$263.2
Michigan	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
New Jersey	$400.1	$379.1	$358.0	$337.0	$315.9	$210.6
North Carolina	$2.9	$2.8	$2.6	$2.5	$2.3	$1.5
Ohio	$2,976.9	$2,820.2	$2,663.5	$2,506.8	$2,350.1	$1,566.8
Pennsylvania	$3,210.0	$3,041.1	$2,872.1	$2,703.2	$2,534.2	$1,689.5
Tennessee	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Virginia	$1,068.3	$1,012.1	$955.9	$899.6	$843.4	$562.3
Washington, D.C.	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
West Virginia	$2,457.1	$2,327.8	$2,198.5	$2,069.1	$1,939.8	$1,293.2
Total	$14,090.3	$13,348.7	$12,607.1	$11,865.5	$11,123.9	$7,415.9

Table 8-8 shows the estimated impact of five different carbon prices on PJM load-weighted LMP. For example, if the carbon price were $25.00 per tonne, the PJM load-weighted average LMP in the first three months of 2023 would have increased by 5.4 percent.[146]

Table 8-8 Estimated impact of carbon price on LMP: January through March, 2022 and 2023

		2022 (Jan - Mar)			2023 (Jan - Mar)		
Scenario	Carbon Price ($/Metric Ton)	Actual LMP ($/MWh)	Estimated LMP ($/MWh)	Percent Change	Actual LMP ($/MWh)	Estimated LMP ($/MWh)	Percent Change
Scenario 1	$5.00	$54.13	$52.09	(3.8%)	$30.28	$29.23	(3.5%)
Scenario 2	$10.00	$54.13	$53.27	(1.6%)	$30.28	$29.90	(1.2%)
Scenario 3	$15.00	$54.13	$54.45	0.6%	$30.28	$30.58	1.0%
Scenario 4	$25.00	$54.13	$56.82	5.0%	$30.28	$31.92	5.4%
Scenario 5	$50.00	$54.13	$62.74	15.9%	$30.28	$35.28	16.5%

Table 8-9 shows the impact of a range of carbon prices on the cost per MWh of producing energy from three basic unit types.[147] [148] For example, if the price of carbon were $50.00 per tonne, the short run marginal costs would increase by $24.52 per MWh for a new combustion turbine (CT) unit, $16.71 per MWh for a new combined cycle (CC) unit and $43.15 per MWh for a new coal plant (CP). Table 8-11 and Table 8-12 show the carbon price impact ($ per MWh) for a range of heat rates and carbon prices for natural gas and coal fired generation.

Table 8-9 Carbon price per MWh by unit type

	Carbon Price per MWh						
Unit Type	Carbon $5/tonne	Carbon $10/tonne	Carbon $15/tonne	Carbon $50/tonne	Carbon $100/tonne	Carbon $200/tonne	Carbon $400/tonne
CT	$2.44	$4.89	$7.33	$24.45	$48.89	$97.79	$195.58
CC	$1.68	$3.37	$5.05	$16.85	$33.70	$67.40	$134.79
CP	$4.31	$8.62	$12.93	$43.09	$86.18	$172.36	$344.73

Table 8-9 also illustrates the effective cost of carbon included in the price of a REC or SREC. For example, the average price of an SREC in New Jersey was $187.78 per credit in the first three months of 2023. The SREC price is paid in addition to the energy price paid at the time the solar energy is produced. The carbon price implied by the SREC price is slightly less than $400 per tonne. Table 8-9 shows that if the MWh produced by the solar resource resulted in avoiding the production of one MWh from a CT, the value of carbon reduction implied by an SREC price of $195.58 is a carbon price of $400 per tonne. This result also assumes that the entire value of the SREC was based on reduced carbon emissions. The SREC price consistent with a carbon price of $50.00 per tonne, assuming that a MWh from a CT is avoided, is $24.45 per MWh.

Applying this method to Tier I and Class I REC and SREC price histories yields the implied carbon prices in Table 8-10. The carbon price implied by the average REC price during the first three months of 2023 in Ohio is $16.69 per tonne which is $2.91 per tonne higher than the RGGI auction price of $13.78 per tonne on March 8, 2023. The carbon price implied by the average price for Washington, DC RECs during the first three months of 2023 is $21.87 per tonne. The implied carbon prices for Virginia, Maryland, New Jersey and Pennsylvania RECs exceed the RGGI clearing price by at least $10 per tonne, and are well below the social cost of carbon which is estimated to be in the range of $50 per tonne.[149] The carbon prices implied by SREC prices have no apparent relationship to carbon prices implied by the REC clearing prices. The carbon prices implied by the SREC prices all exceed the carbon prices implied by the corresponding REC prices, and all exceed the social cost of carbon.

146 LMPs are recalculated to account for the defined cost of carbon emissions on marginal units' offer prices. The LMP calculation is not based on a counterfactual redispatch of the system to determine the marginal units and the marginal costs that would have occurred if all units had made all offers at short run marginal cost. See Technical Reference for PJM Markets, "Calculation and Use of Generator Sensitivity/Unit Participation Factors," <http://www.monitoringanalytics.com/reports/Technical_References/references.shtml>.

147 Heat rates from: *2021 State of the Market Report for PJM: January through June*, Section 7: Net Revenue, Table 7-3.

148 Prices reflect carbon emissions rates from *Table A.3. Carbon Dioxide Uncontrolled Emission Factors*, EIA, <https://www.eia.gov/electricity/annual/html/epa_a_03.html> (Accessed July 27, 2022).

149 "Technical Update of the Social Cost of Carbon for Regulatory Impact Analysis – Under Executive Order 12899," Interagency Working Group on the Social Cost of Greenhouse Gases, United States Government, (Aug. 2016), <https://19january2017snapshot.epa.gov/sites/production/files/2016-12/documents/sc_co2_tsd_august_2016.pdf>.

Table 8-10 Implied carbon price based on REC and SREC prices: 2014 through March 2023

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Jurisdiction with Tier I or Class I REC										
Delaware	$35.28	$32.01	$33.01	$10.29	$11.60	$16.10	$19.94			
Maryland	$28.54	$29.27	$26.17	$23.19	$21.35	$17.81	$19.98	$27.15	$30.09	$35.50
New Jersey	$21.10	$25.37	$27.01	$24.08	$22.08	$19.25	$20.54	$26.85	$28.38	$35.62
Ohio	$10.19	$8.54	$5.30	$6.29	$11.21	$14.04	$16.33	$16.39	$16.45	$16.69
Pennsylvania	$26.74	$28.96	$26.43	$23.42	$21.53	$17.96	$20.06	$26.44	$29.76	$35.12
Virginia								$20.56	$21.21	$24.21
Washington, D.C.		$3.20	$4.05	$4.90	$4.69	$5.52	$12.55	$15.87	$19.24	$21.87
Jurisdiction with Solar REC										
Delaware	$117.60	$85.66	$86.75	$35.80	$17.38					
Maryland	$293.59	$251.99	$183.64	$128.05	$87.27	$84.19	$101.68	$120.95	$108.77	$96.56
New Jersey	$327.20	$389.91	$425.49	$460.60	$446.35	$410.31	$394.18	$409.69	$420.80	$384.05
Ohio	$82.56	$45.25	$36.26	$31.92	$21.73	$26.65				
Pennsylvania	$76.13	$67.09	$55.22	$43.97	$28.16	$51.65	$63.80	$73.78	$85.62	$81.62
Washington, D.C.	$960.35	$997.05	$996.49	$868.79	$842.89	$851.39	$869.41	$843.90	$843.80	$842.51
Regional Greenhouse Gas Initiative										
RGGI clearing price	$5.21	$6.72	$4.93	$3.77	$4.86	$5.98	$7.06	$10.59	$14.84	$13.78

Table 8-11 Carbon price for natural gas fired generators[150]

	Carbon Price ($ per MWh)										
	Carbon ($ per tonne)										
Heat Rate (Btu per kWh)	$10.00	$15.00	$20.00	$25.00	$30.00	$35.00	$40.00	$45.00	$50.00	$55.00	$60.00
6,000	$3.17	$4.76	$6.35	$7.94	$9.52	$11.11	$12.70	$14.29	$15.87	$17.46	$19.05
6,500	$3.44	$5.16	$6.88	$8.60	$10.32	$12.04	$13.76	$15.48	$17.20	$18.92	$20.63
7,000	$3.70	$5.56	$7.41	$9.26	$11.11	$12.96	$14.81	$16.67	$18.52	$20.37	$22.22
7,500	$3.97	$5.95	$7.94	$9.92	$11.90	$13.89	$15.87	$17.86	$19.84	$21.83	$23.81
8,000	$4.23	$6.35	$8.47	$10.58	$12.70	$14.81	$16.93	$19.05	$21.16	$23.28	$25.40
8,500	$4.50	$6.75	$8.99	$11.24	$13.49	$15.74	$17.99	$20.24	$22.49	$24.74	$26.98
9,000	$4.76	$7.14	$9.52	$11.90	$14.29	$16.67	$19.05	$21.43	$23.81	$26.19	$28.57
9,500	$5.03	$7.54	$10.05	$12.57	$15.08	$17.59	$20.11	$22.62	$25.13	$27.65	$30.16
10,000	$5.29	$7.94	$10.58	$13.23	$15.87	$18.52	$21.16	$23.81	$26.45	$29.10	$31.75
10,500	$5.56	$8.33	$11.11	$13.89	$16.67	$19.44	$22.22	$25.00	$27.78	$30.56	$33.33
11,000	$5.82	$8.73	$11.64	$14.55	$17.46	$20.37	$23.28	$26.19	$29.10	$32.01	$34.92
11,500	$6.08	$9.13	$12.17	$15.21	$18.25	$21.30	$24.34	$27.38	$30.42	$33.47	$36.51
12,000	$6.35	$9.52	$12.70	$15.87	$19.05	$22.22	$25.40	$28.57	$31.75	$34.92	$38.10
12,500	$6.61	$9.92	$13.23	$16.53	$19.84	$23.15	$26.45	$29.76	$33.07	$36.38	$39.68
13,000	$6.88	$10.32	$13.76	$17.20	$20.63	$24.07	$27.51	$30.95	$34.39	$37.83	$41.27
13,500	$7.14	$10.71	$14.29	$17.86	$21.43	$25.00	$28.57	$32.14	$35.71	$39.29	$42.86
14,000	$7.41	$11.11	$14.81	$18.52	$22.22	$25.93	$29.63	$33.33	$37.04	$40.74	$44.44
14,500	$7.67	$11.51	$15.34	$19.18	$23.02	$26.85	$30.69	$34.52	$38.36	$42.20	$46.03
15,000	$7.94	$11.90	$15.87	$19.84	$23.81	$27.78	$31.75	$35.71	$39.68	$43.65	$47.62

150 Prices reflect carbon emission rates from *Table A.3. Carbon Dioxide Uncontrolled Emission Factors*, EIA, <https://www.eia.gov/electricity/annual/html/epa_a_03.html> (Accessed July 27, 2022).

Table 8-12 Carbon price for coal fired generators[151]

	Carbon Price ($ per MWh)										
	Carbon ($ per tonne)										
Heat Rate (Btu per kWh)	$10.00	$15.00	$20.00	$25.00	$30.00	$35.00	$40.00	$45.00	$50.00	$55.00	$60.00
9,000	$8.39	$12.58	$16.77	$20.96	$25.16	$29.35	$33.54	$37.73	$41.93	$46.12	$50.31
9,500	$8.85	$13.28	$17.70	$22.13	$26.55	$30.98	$35.40	$39.83	$44.26	$48.68	$53.11
10,000	$9.32	$13.98	$18.63	$23.29	$27.95	$32.61	$37.27	$41.93	$46.58	$51.24	$55.90
10,500	$9.78	$14.67	$19.57	$24.46	$29.35	$34.24	$39.13	$44.02	$48.91	$53.81	$58.70
11,000	$10.25	$15.37	$20.50	$25.62	$30.75	$35.87	$40.99	$46.12	$51.24	$56.37	$61.49
11,500	$10.71	$16.07	$21.43	$26.79	$32.14	$37.50	$42.86	$48.22	$53.57	$58.93	$64.29
12,000	$11.18	$16.77	$22.36	$27.95	$33.54	$39.13	$44.72	$50.31	$55.90	$61.49	$67.08
12,500	$11.65	$17.47	$23.29	$29.12	$34.94	$40.76	$46.58	$52.41	$58.23	$64.05	$69.88
13,000	$12.11	$18.17	$24.22	$30.28	$36.34	$42.39	$48.45	$54.50	$60.56	$66.62	$72.67
13,500	$12.58	$18.87	$25.16	$31.44	$37.73	$44.02	$50.31	$56.60	$62.89	$69.18	$75.47
14,000	$13.04	$19.57	$26.09	$32.61	$39.13	$45.65	$52.18	$58.70	$65.22	$71.74	$78.26
14,500	$13.51	$20.26	$27.02	$33.77	$40.53	$47.28	$54.04	$60.79	$67.55	$74.30	$81.06
15,000	$13.98	$20.96	$27.95	$34.94	$41.93	$48.91	$55.90	$62.89	$69.88	$76.87	$83.85
15,500	$14.44	$21.66	$28.88	$36.10	$43.32	$50.54	$57.77	$64.99	$72.21	$79.43	$86.65
16,000	$14.91	$22.36	$29.81	$37.27	$44.72	$52.18	$59.63	$67.08	$74.54	$81.99	$89.44
16,500	$15.37	$23.06	$30.75	$38.43	$46.12	$53.81	$61.49	$69.18	$76.87	$84.55	$92.24
17,000	$15.84	$23.76	$31.68	$39.60	$47.52	$55.44	$63.36	$71.27	$79.19	$87.11	$95.03
17,500	$16.30	$24.46	$32.61	$40.76	$48.91	$57.07	$65.22	$73.37	$81.52	$89.68	$97.83
18,000	$16.77	$25.16	$33.54	$41.93	$50.31	$58.70	$67.08	$75.47	$83.85	$92.24	$100.62

State Renewable Portfolio Standards

Ten of 14 PJM jurisdictions have enacted legislation that requires that a defined percentage of retail load be served by renewable resources, for which there are many standards and definitions. These requirements are known as renewable portfolio standards, or RPS. In PJM jurisdictions that have adopted an RPS, load serving entities are required by law to meet defined shares of load using specific renewable and/or alternative energy sources commonly called eligible technologies. Load serving entities may generally fulfill these obligations in one of two ways: they may use their own generation resources classified as eligible technologies to produce power or they may purchase renewable energy credits (RECs) that represent a known quantity of power produced with eligible technologies by other market participants or in other geographical locations. Load serving entities that fail to meet the percent goals set in their jurisdiction's RPS must pay penalties (alternative compliance payments).

Renewable energy sources replenish naturally in a short period of time but are flow limited and include solar, geothermal, wind, biomass and hydropower from flowing water. Renewable energy sources are virtually inexhaustible in duration but limited in the amount of energy that is available per unit of time. Nonrenewable energy sources do not replenish in a short period of time and include crude oil, natural gas, coal and uranium (nuclear energy).[152] Some state rules allow nonrenewable energy sources as part of their Renewable Portfolio Standard.

As of March 31, 2023, Delaware, Illinois, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Virginia and Washington, DC had mandatory renewable portfolio standards that include penalties.

As of March 31, 2023, Indiana had voluntary renewable portfolio standards that do not require participation and do not include noncompliance penalties. Incentives are offered to load serving entities to develop renewable generation or, to a more limited extent, purchase RECs. The voluntary standard was enacted by the Indiana legislature in 2011, but no load serving entities have volunteered to participate in the program.[153]

As of March 31, 2023, Kentucky, Tennessee and West Virginia had no renewable portfolio standards.

How each state satisfies its renewable portfolio standard requirements should be more transparent. While some jurisdictions publish transparent information regarding total REC generation, how the standard is fulfilled and the total cost to the state, some jurisdictions do not provide the same level of detail and there can be a significant lag from the end of the compliance year to the publication of the information. Some states provide adequate information

151 Prices reflect carbon emission rates for refined coal in *Table A.3. Carbon Dioxide Uncontrolled Emission Factors*, EIA, <https://www.eia.gov/electricity/annual/html/epa_a_03.html> (Accessed July 27, 2022).

152 *Renewable Energy Explained*, U.S. Energy Information Administration, <https://www.eia.gov/energyexplained/index.php?page=renewable_home> (Accessed April 18, 2023).

153 See the Indiana Utility Regulatory Commission's "2021 Annual Report," at 37 (Oct. 2021) <https://www.in.gov/iurc/2981.htm>.

with respect to the total cost for the RPS, where the RECs originated that fulfill the RPS requirements, and if the state fulfilled the RPS goals. Pennsylvania and Maryland both provide more information than other states and serve as a model for other states. The MMU recommends that jurisdictions with a renewable portfolio standard make the compliance data and cost data available in a more complete and transparent manner.

Since a REC may be applied in years other than the year in which it was generated, each vintage of RECs for each state has a different price. For example, the Pennsylvania Alternative Energy Portfolio Standard allows an electric distribution company or generation supplier to retain RECs from the current reporting year for use toward satisfying their REC obligation in either of the two subsequent reporting years.[154]

Beginning in March 2023, RECs for GATS generators will be hourly time stamped certificates.[155] Prior to March 2023, PJM EIS issued RECs based on how much a generator produced in a month.

Table 8-13 shows the percent of retail electric load that must be served by renewable and/or alternative energy resources under each PJM jurisdictions' RPS by year.

Table 8-13 Renewable and alternative energy standards of PJM jurisdictions: 2022 to 2032[156 157]

Jurisdiction with RPS	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Delaware	22.00%	23.00%	24.00%	25.00%	25.50%	26.00%	26.50%	27.00%	28.00%	30.00%	32.00%
Illinois	20.50%	22.00%	23.50%	25.00%	28.00%	31.00%	34.00%	37.00%	40.00%	40.00%	40.00%
Maryland	32.60%	34.45%	36.35%	38.25%	41.00%	44.75%	46.50%	53.00%	53.50%	53.50%	53.50%
Michigan	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%
New Jersey	24.50%	29.50%	37.50%	40.50%	43.50%	46.50%	49.50%	52.50%	52.50%	52.50%	52.50%
North Carolina	12.50%	12.50%	12.50%	12.50%	12.50%	12.50%	12.50%	12.50%	12.50%	12.50%	12.50%
Ohio	6.50%	7.00%	7.50%	8.00%	8.50%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Pennsylvania	18.00%	18.00%	18.00%	18.00%	18.00%	18.00%	18.00%	18.00%	18.00%	18.00%	18.00%
Virginia (Phase I utilities)	7.00%	8.00%	10.00%	14.00%	17.00%	20.00%	24.00%	27.00%	30.00%	33.00%	36.00%
Virginia (Phase II utilities)	17.00%	20.00%	23.00%	26.00%	29.00%	32.00%	35.00%	38.00%	41.00%	45.00%	49.00%
Washington, DC	32.50%	38.75%	45.00%	52.00%	59.00%	66.00%	73.00%	80.00%	87.00%	94.00%	100.00%

The Climate and Equitable Jobs Act (CEJA), which became effective on September 15, 2021 in Illinois, increased the RPS target percent from 25 percent by 2025 to 40 percent by 2030. CEJA also increased the quotas for RECs sourced from new wind and new photovoltaic resources, and made changes to eligible technologies and geographic restrictions. See Table 8-14 for details.

Updates to the Maryland RPS became effective on June 1, 2021. Maryland Senate Bill 65 changed the intermediate RPS target levels while maintaining the target of 50.0 percent renewable by 2030.[158] Part of the legislation was to eliminate resources fueled by black liquor as a Tier 1 eligible technology. Senate Bill 65 reduced the penalty for solar non compliance from $100 per credit to $80 per credit, and extended the Tier 2 standard which was scheduled to expire with the 2020 compliance year.

The Delaware General Assembly passed new RPS legislation on February 10, 2021. The new law updates the Delaware RPS targets from 25 percent in 2025 to 40 percent in 2035.[159] Additional details are provided in Table 8-14.

154 Pennsylvania General Assembly, "Alternative Energy Portfolio Standards Act – Enactment Act of Nov. 30, 2004, P.L. 1672, No. 213," Section (e)(6).
155 "PJM EIS to Produce Energy Certificates Hourly", PJM Environmental Information Services (February 13, 2023) <https://www.pjm-eis.com/-/media/about-pjm/newsroom/2023-releases/20230213-pjm-eis-to-produce-energy-certificates-hourly.ashx>.
156 This shows the total standard of alternative resources in all PJM jurisdictions, including Tier I and Tier II.
157 The table reflects calendar year standards for Maryland, Washington, DC, Ohio, and North Carolina. The standards for the remaining jurisdictions are for compliance years that begin on June 1, CCYY and end on May 31 of the following year.
158 *Senate Bill 65 Electricity – Renewable Energy Portfolio Standard – Tier 2 Renewable Sources, Qualifying Biomass, and Compliance Fees*, Maryland General Assemble (2021) <https://mgaleg.maryland.gov/mgawebsite/Legislation/Details/sb0065?ys=2021RS>.
159 See Senate Bill 33, Delaware General Assembly (February 10, 2021) <https://legis.delaware.gov/BillDetail?legislationId=48278>.

On April 11, 2020, the Virginia legislature passed a new law that replaced Virginia's current voluntary RPS with a mandatory RPS.[160] The new law requires by 2050 that 100 percent of energy sold by phase I utilities must come from RPS eligible resources; and 100 percent of energy sold by phase II utilities must come from RPS eligible resources by 2045.[161] [162] Intermediate RPS targets begin in 2021 with a 6.0 percent standard for phase I utilities and a 14.0 percent standard for phase II utilities. Eligible RPS resources include wind, solar, hydroelectric, landfill gas and biomass resources.

In 2018, New Jersey passed legislation that included provisions promoting the development of solar power in the state.[163] The Board of Public Utilities is directed to develop and provide an orderly transition to a new or modified program to support distributed solar. The Board must also design a Community Solar Energy Pilot Program that would "permit customers of an electric public utility to participate in a solar energy project that is remotely located from their properties but is within their electric public utility service territory to allow for a credit to the customer's utility bill equal to the electricity generated that is attributed to the customer's participation in the solar energy project." The pilot program would convert into a permanent program within three years. The statute targets the development of 600 MW of electric storage by 2021 and 2,000 MW by 2030.

On May 18, 2021, Maryland enacted legislation doubling the limit on net metered capacity from 1,500 to 3,000 MW.[164] The legislation is expected to boost the installation of distribution level solar power.

160 See "Virginia Clean Economy Act," (April 12, 2020) <https://www.governor.virginia.gov/newsroom/all-releases/2020/april/headline-856056-en.html>.

161 A phase I utility is an investor-owned incumbent electric utility that was, as of July 1, 1999, not bound by a rate case settlement adopted by the Commission that extended in its application beyond January 1, 2002, and a phase II utility is an investor-owned incumbent electric utility that was bound by such a settlement (§ 56-585.1 of the Virginia Code).

162 APCO (AEP) is a phase I utility and Dominion Energy Virginia is a phase II utility. Cooperatives are not subject to the RPS

163 N.J. S. 2314/A. 3723.

164 Md. Code Ann § 7-306(d) & 7-306.2(g) (HB 569).

On July 9, 2021, New Jersey enacted legislation establishing a new program for SRECs under the BPU.[165] Through the SREC-II program, the BPU distribute solar renewable certificates to qualifying solar power facilities. The legislation includes incentives for at least 1,500 MW of behind the meter solar facilities and 750 MW of community solar by 2026. It also includes a new competitive solicitation process to incentivize at least 1,500 MW of large-scale solar power facilities by 2026, and develops siting criteria for large-scale solar projects.

165 N.J. P.L.2021 (S. 2605/A 4554).

Table 8-14 summarizes recent rules changes in Ohio, Maryland, New Jersey, and Washington, DC.

Table 8-14 Recent changes in RPS rules[166 167 168 169 170 171 172]

Jurisdiction	Legislation	Effective Date	Summary of changes
Illinois	Climate and Equitable Jobs Act (Public Act 102-0662)	September 15, 2021	Updated the RPS target to 40.0 percent by 2030. The previous target of 25.0 percent by 2025 is still required. Updated the requirement for RECs from new wind generation from 2,000 GWH annually to 4,500 GWH beginning in the 2021/2022 delivery year; increasing to 20,250 GWH in 2030/2031. Updated the requirement for RECs from new photovoltaic generation from 2,000 GWH annually to 5,500 GWH beginning in the 2021/2022 delivery year; increasing to 24,750 GWH in 2030/2031. Removed tree waste as an energy source for eligible resources and added waste heat to power systems and qualified combined heat and power systems as eligible resources. Updated the geographic restrictions to allow RECs from utility scale wind or photovoltaic resources that are deliverable via high voltage direct current transmission.
Maryland	Senate Bill 65	June 1, 2021	Maintains theTier 1 target of 50.0 percent in 2030 with 14.5 percent solar carve out, but changes the intermediary target levels beginning in 2022. The alternatvie compliance payment for solar was reduced and the definition of Tier 1 resource now excludes generators fueled by black liquor. Extends indefinitely the Tier 2 target of 2.5 percent which was set to expire in 2020. Tier 2 resources are defined as hydroelectric power other than pumped storage.
Delaware	151st General Assembly Senate Bill 33	February 1, 2021	Increases the RPS target from 25.0 percent in 2025 to 40.0 percent in 2035. Sets the solar carve out requirement to 10.0 percent in 2035. Establishes intermediary target levels for total RPS and the solar carve out for compliance years 2026 through 2034. Lowered the solar alternative compliance payment (SACP) from $400 per credit to $150 per credit.
Virginia	Virginia Clean Economy Act	April 11, 2020	Replaces the voluntary RPS with a mandartory RPS beginning in January 2021. The legislation requires 100 percent clean energy by 2050 for phase I utilities and 100 percent clean energy by 2045 for phase II utilities. Intermediate target levels begin in 2021 with 6 percent for phase I utilities and 14 percent for phase II utilities.
Ohio	House Bill 6	October 22, 2019	Reduced the RPS percent for each year beginning in 2020. The 2020 standard was reduced from 6.5 percent to 5.5 percent; the 2026 standard was reduced from 12.5 percent to 8.5 percent. The legislation also removed language that had previously indicated that the standard would remain at the 2026 level for each year after 2026. The solar carve out was removed for compliance year 2020 and beyond. Prior to the recent legislation, the solar carve out was 0.26 percent for 2020, increased to 0.50 percent for 2026, and remained at 0.50 percent for subsequent years.
Maryland	Clean Energy Jobs Act	May 25, 2019	Established a new Tier I target of 50.0 percent in 2030; previously the 2030 Tier I standard was 25.0 percent. The 2019 Tier I standard increased from 20.4 percent to 20.7. The solar carve out percent for 2019 increased from 1.95 percent to 5.50 percent. The solar carve out percent for 2030 increased from 2.5 percent to 14.5 percent. The 2.5 percent Tier II standard, scheduled to end in 2018, was extended through 2020.
Washington, D.C.	CleanEnergy DC Omnibus Amendment Act of 2018	March 22, 2019	Established a 100 percent Tier I renewable standard by 2032. Previously, the 2032 target was 50.0 percent. Tier I increases start in 2020, going from 20.0 percent to 26.25 percent. The 2020 solar carve out will increase from 1.58 percent to 2.175 percent. The 2041 target for the solar carve out is 10.0 percent.

New Jersey and Maryland have taken significant steps to promote offshore wind. Both states enacted legislation for offshore wind renewable energy credits (ORECs) in 2010.[173]

On May 24, 2018, New Jersey enacted a statute directing the Board of Public Utilities to create an OREC program targeting installation of at least 3,500 MW of offshore wind capacity by 2030 (plus 2,000 MW of energy storage capacity).[174] The New Jersey statute also reinstates certain tax incentives for offshore wind manufacturing activities. Governor Murphy has issued Executive Order No. 8, which calls for full implementation of the statute. The offshore wind target 3,500

166 Illinois Climate and Equitable Jobs Act (Public Act 102-0662), Section 90-30 (September 15, 2021).
167 See "Virginia Clean Economy Act," (April 12, 2020) <https://www.governor.virginia.gov/newsroom/all-releases/2020/april/headline-856056-en.html>.
168 See Ohio Legislature House, 133rd Assembly, Bill No. 6, "Ohio Clean Air Program," effective Date October 22, 2019, <https://www.legislature.ohio.gov/legislation/legislation-summary?id=GA133-HB-6>.
169 See Maryland State Legislature, Senate Bill No. 516, "Clean Energy Jobs," Passed May 25, 2019, <https://legiscan.com/md/text/sb516/2019>.
170 D.C. Law 22-257 "CleanEnergy DC Omnibus Amendment Act of 2018," Effective March 22, 2019, <https://code.dccouncil.us/dc/council/laws/22-257.html>.
171 See Senate Bill 33, Delaware General Assembly (February 10, 2021) <https://legis.delaware.gov/BillDetail?legislationId=48278>.
172 *Senate Bill 65 Electricity – Renewable Energy Portfolio Standard – Tier 2 Renewable Sources, Qualifying Biomass, and Compliance Fees*, Maryland General Assemble (2021) <https://mgaleg.maryland.gov/mgawebsite/Legislation/Details/sb0065?ys=2021RS>.
173 See Offshore Wind Economic Development Act of 2010, P.L. 2010, c. 57, as amended, N.J.S.A. 48:3-87 to -87.2.
174 N.J. S. 2314/A. 3723.

MW by 2030 has since been replaced by a target of 7,500 MW by 2035.[175] The BPU opened a 100 day application window for qualified offshore wind projects on September 20, 2018, and on June, 21, 2019, the first award for a 1,100 MW offshore wind project was granted to Orsted.[176 177]

On December 17, 2021, the Maryland Public Service Commission awarded ORECs in its Round 2 solicitation to the 846 MW Skipjack Wind 2 offshore project, owned by Skipjack Offshore Energy LLC, an Orsted subsidiary, and to the 808.5 MW Momentum Wind offshore project, owned by US Wind Inc.[178] ORECs for Skipjack Wind 2 have a levelized price of $71.61; ORECs for Momentum Wind have a levelized price of $54.17.[179] Both projects are expected to become operational before the end of 2026.[180] In 2017, Round 1 ORECs were awarded to Deepwater Wind's 120-MW Skipjack Wind Farm, later acquired by Orsted, and U.S. Wind's 248 MW project.[181]

On July 1, 2019, Dominion Energy announced the beginning of construction on an offshore wind demonstration project. The project consists of two 6 MW offshore wind turbines.[182] In September 2019, Dominion filed an interconnection agreement with PJM associated with its proposal to develop a 2,600 MW offshore wind farm.[183]

Each PJM jurisdiction with an RPS identifies the type of generation resources that may be used for compliance. These resources are often called eligible technologies. Some PJM jurisdictions with RPS group different eligible technologies into tiers based on the magnitude of their environmental impact. Of the nine PJM jurisdictions with mandatory RPS, Maryland, New Jersey, Pennsylvania, and Washington, DC group the eligible technologies that must be used to comply with their RPS programs into Tier I and Tier II resources.[184] Although there are minor differences across these four jurisdictions' definitions of Tier I resources, technologies that use solar photovoltaic, solar thermal, wind, ocean, tidal, biomass, low-impact hydro, and geothermal sources to produce electricity are classified as Tier I resources. Table 8-15 shows the Tier I standards for PJM states.[185] All eligible technologies for the RPS standards in Table 8-15 satisfy the EIA definition of renewable energy.[186]

Table 8-15 Tier I / Class I renewable standards of PJM jurisdictions: 2022 to 2032

Jurisdiction with RPS	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Maryland	30.10%	31.95%	33.85%	35.75%	38.50%	42.25%	44.00%	50.50%	51.00%	51.00%	51.00%
New Jersey	22.00%	27.00%	35.00%	38.00%	41.00%	44.00%	47.00%	50.00%	50.00%	50.00%	50.00%
Pennsylvania	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%
Washington, DC	32.50%	38.75%	45.00%	52.00%	59.00%	66.00%	73.00%	80.00%	87.00%	94.00%	100.00%

Delaware, Illinois, Michigan, North Carolina, Virginia and Ohio do not classify the resources eligible for their RPS standards by tiers. In these states eligible technologies are largely but not completely renewable resources.[187]

RECs do not need to be used during the year in which they are generated. The result is that there may be multiple prices for a REC based on the year in which it was generated. RECs typically have a shelf life of five years during which they can be used to satisfy a state's RPS requirement. For example if a load serving entity (LSE) owns renewable generation and the renewable generation exceeds the LSE's RECs purchase obligation for the current year, the LSE can either sell the REC to another LSE or hold the REC for use in a subsequent year.

PJM GATS makes data available for the amount of eligible RECs by jurisdiction. Eligible RECs are not the amount of actual RECs generated for that timeframe. A REC that is created may be eligible in multiple jurisdictions resulting in

175 Executive Order 92, Philip D. Murphy, Governor of New Jersey (November 19, 2019) <https://nj.gov/infobank/eo/056murphy/approved/eo_archive.html>.

176 BPU Docket No. QO18080851.

177 "New Jersey Board of Public Utilities Awards Historic 1,100 MW Offshore Wind Solicitation to Orsted's Ocean Wind Project," New Jersey BPU Press Release (June 21, 2019) <https://nj.gov/bpu/newsroom/2019/approved/20190621.html>.

178 "Orsted, US Wind Triumph with 1.6 GW in Maryland Offshore Tender," Renewables Now (December 20, 2021) <https://renewablesnow.com/news/rsted-us-wind-triumph-with-16-gw-in-maryland-offshore-tender-766237/>.

179 *Id.*

180 *Id.*

181 "Orsted Acquires Deepwater Wind and creates leading US Offshore Wind Platform," ORSTED Press Release (August 10, 2018).

182 "Construction Begins on Dominion Energy Offshore Wind Project," Dominion Energy News Release (July 1, 2019) <https://news.dominionenergy.com/2019-07-01-Construction-Begins-on-Dominion-Energy-Offshore-Wind-Project>.

183 "Dominion Energy Announces Largest Offshore Wind Project in US," Dominion Energy News Release (September 19, 2019) <https://news.dominionenergy.com/2019-09-19-Dominion-Energy-Announces-Largest-Offshore-Wind-Project-in-US>.

184 New Jersey separates technologies into Class I/Class II resources in a manner that is consistent with the other jurisdictions' Tier I/Tier II categorizations.

185 This includes New Jersey's Class I renewable standard.

186 *Renewable Energy Explained*, U.S. Energy Information Administration, <https://www.eia.gov/energyexplained/index.php?page=renewable_home> (Accessed October 17, 2019).

187 Michigan's Public Act 342, effective April 20, 2017, removed nonrenewable technologies (e.g. coal gasification, industrial cogeneration, and coal with carbon capture) from the list of RPS eligible technologies.

an over representation of generated RECs. This means if one REC is retired in Pennsylvania, the total amount of eligible RECs will reduce by more than one REC.

The REC prices are the average price for each vintage of REC, defined by the year in which the associated power was generated, regardless of when the REC is consumed. REC prices are required to be publicly disclosed in Maryland, Pennsylvania and Washington, DC, but in the other states REC prices are not publicly available.

Figure 8-3 shows the average Tier I REC price by jurisdiction from January 1, 2009, through March 31, 2023. Tier I REC prices are lower than SREC prices. Several states have more stringent geographical restrictions for SRECs and higher alternative compliance payments (ACP) than for RECs. For example, the average SREC price for the first three months of 2023 in Washington, DC was $411.94 and the average Tier I REC price for the first three months of 2023 in Washington, DC was $10.69. The DC RPS requires SRECs to be sourced from within DC while Tier I RECs may be sourced from anywhere within the PJM footprint. Also the DC solar ACP is $500 per SREC compared to $50 per REC for Tier I compliance.

Figure 8-3 Average Tier I REC price by jurisdiction: 2009 through March 2023

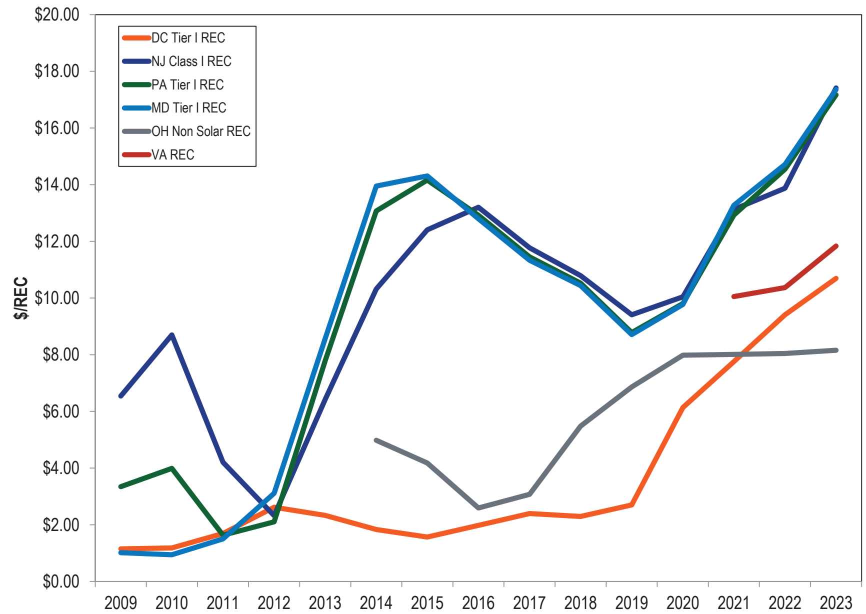


Figure 8-4 and Table 8-16 show the fulfillment of Tier I equivalent RPS requirement for 2017 through 2022 by state and by import and internal RECs and by carbon producing and noncarbon producing RECs.[188] Depending on the state, the RPS requirement can be fulfilled by wind, solar, hydro ("Noncarbon REC") or with landfill gas, captured methane, wood, black liquor, and other fuels. ("Carbon Producing REC"). States' Tier I requirements are not all carbon free. The Illinois RPS, beginning in 2019, is fulfilled by noncarbon RECs, but all other state Tier I equivalent RPS requirements allow carbon producing RECs to fulfill the RPS requirements. Figure 8-4 shows the use of imported and local carbon producing RECs and imported and local noncarbon RECs by state to meet the RPS requirements. Table 8-16 shows the percent of imported and local carbon producing RECs and imported and local noncarbon RECs by state used to meet the RPS requirements. For example, Virginia imported

188 Retired REC information obtained through PJM GATS <https://gats.pjm-eis.com/gats2/PublicReports/RPSRetiredCertificatesReportingYear> (Accessed April 18, 2023). The timing of the REC retirement reports varies by state and the 2022 reporting year data may be incomplete for some states.

80.2 percent of the RECs used to satisfy the RPS in 2021, its first year with a mandatory RPS, and 80.7 percent of the Virginia's 2021 RECs were carbon free. Ohio met its RPS target using 85.9 percent imported RECs, and 14.1 percent State RECs for the 2021 compliance year. Ohio met its RPS target using 75.0 percent noncarbon producing RECs, and 25.0 percent carbon producing RECs for the 2021 compliance year. Illinois met its RPS target using 19.0 percent imported RECs, and 81.0 percent State RECs for the 2021 compliance year. Illinois met its RPS target using 100.0 percent noncarbon producing RECs for the 2019, 2020 and 2021 compliance years.

Figure 8-4 State fulfillment of Tier I equivalent RPS: 2017 through 2022

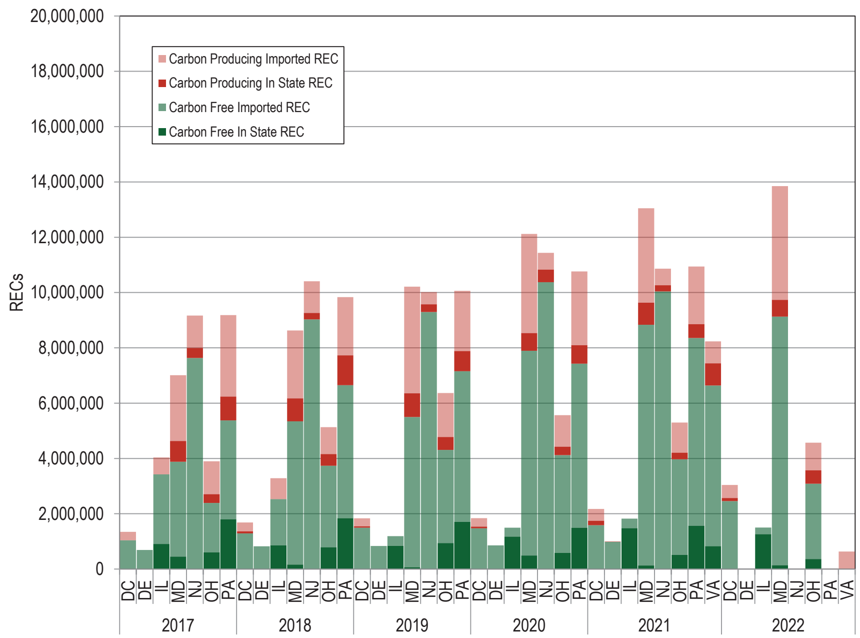


Table 8-16 State fulfillment of Tier I equivalent RPS: 2017 through 2022

		Carbon Free REC		Carbon Producing REC	
Year	REC Type	In State	Import	In State	Import
2017	DE New Eligible	0.7%	99.3%	0.0%	0.0%
	DC Tier I	0.0%	77.2%	0.0%	22.8%
	OH Renewable Energy Source	15.6%	45.8%	8.1%	30.6%
	IL Renewable	22.5%	62.3%	0.0%	15.2%
	MD Tier I	6.5%	48.9%	10.7%	34.0%
	NJ Class I	0.1%	83.2%	3.9%	12.8%
	PA Tier I	19.6%	38.9%	9.4%	32.0%
2018	DE New Eligible	0.4%	99.6%	0.0%	0.0%
	DC Tier I	0.0%	76.5%	4.5%	19.0%
	OH Renewable Energy Source	15.4%	57.4%	8.3%	18.9%
	IL Renewable	26.1%	51.0%	0.0%	22.9%
	MD Tier I	1.9%	60.1%	9.6%	28.5%
	NJ Class I	0.0%	86.7%	2.3%	11.0%
	PA Tier I	18.7%	48.9%	10.9%	21.4%
2019	DE New Eligible	0.3%	99.7%	0.0%	0.0%
	DC Tier I	0.0%	81.5%	2.8%	15.7%
	OH Renewable Energy Source	14.7%	53.0%	7.3%	25.0%
	IL Renewable	70.5%	29.5%	0.0%	0.0%
	MD Tier I	0.7%	53.2%	8.4%	37.8%
	NJ Class I	0.1%	92.7%	2.8%	4.4%
	PA Tier I	17.0%	54.2%	7.2%	21.7%
2020	DE New Eligible	0.9%	99.1%	0.0%	0.0%
	DC Tier I	0.0%	80.1%	3.3%	16.6%
	OH Renewable Energy Source	10.5%	63.5%	5.5%	20.5%
	IL Renewable	78.3%	21.7%	0.0%	0.0%
	MD Tier I	4.1%	61.1%	5.3%	29.6%
	NJ Class I	0.1%	90.6%	4.0%	5.3%
	PA Tier I	13.9%	55.1%	6.2%	24.8%
2021	DE New Eligible	0.3%	99.0%	0.7%	0.0%
	DC Tier I	0.0%	72.9%	7.4%	19.7%
	OH Renewable Energy Source	9.6%	65.3%	4.4%	20.6%
	IL Renewable	81.0%	19.0%	0.0%	0.0%
	MD Tier I	1.0%	66.7%	6.1%	26.1%
	NJ Class I	0.1%	92.3%	2.0%	5.5%
	PA Tier I	14.4%	62.0%	4.6%	19.1%
	VA Renewable	10.1%	70.6%	9.7%	9.6%
2022	DE New Eligible				
	DC Tier I	0.0%	80.8%	3.7%	15.5%
	OH Renewable Energy Source	8.0%	59.5%	10.6%	21.9%
	IL Renewable	83.8%	16.2%	0.0%	0.0%
	MD Tier I	1.0%	64.9%	4.4%	29.7%
	NJ Class I	0.0%	0.0%	0.0%	100.0%
	PA Tier I	35.3%	55.1%	2.5%	7.1%
	VA Renewable	0.0%	0.5%	0.0%	99.5%

Table 8-17 shows the percent of retail electric load that must be served by Tier II or a specific type of resource under each PJM jurisdiction's RPS by year. Tier II resources are generally not renewable resources. Table 8-17 also shows specific technology requirements that PJM jurisdictions have added to their renewable portfolio standards. The standards shown in Table 8-17 are included in the total RPS requirements presented in Table 8-13. Maryland, New Jersey and Pennsylvania have Tier II or Class II standards, which allow specific nonrenewable technology types, such as waste coal units located in Pennsylvania, to qualify for renewable energy credits. Washington, DC previously had Tier II standards. The Washington, DC tier II standard was discontinued at the end of the 2019 compliance year. By 2024, North Carolina's RPS requires that 0.2 percent of power be generated using swine waste and that 900 GWh of power be produced by poultry waste in 2020. Maryland established a minimum standard for offshore wind in 2017 that takes effect in 2021 with a requirement that 1.37 percent of load be served by offshore wind. The standard increases to 2.03 percent in 2023.[189]

Tier II prices are lower than SREC and Tier I REC prices. Figure 8-5 shows the average Tier II REC price by jurisdiction for January 1, 2009, through March 31, 2023. Maryland, New Jersey and Pennsylvania are the only states with a Tier II standard in 2023.[190] The average Pennsylvania Tier II REC price for the first three months of 2023 was $16.50, 55.9 percent higher than the average price over the first three months of 2022. The average New Jersey Class II REC price for the first three months of 2023 was $16.46, 53.9 percent higher than the average price for the first three months of 2022. The average Maryland Tier II REC price for the first three months of 2023 was $8.92, 6.0 percent higher than the average price over the first three months of 2022.[191]

Table 8-17 Additional renewable standards of PJM jurisdictions: 2022 to 2032

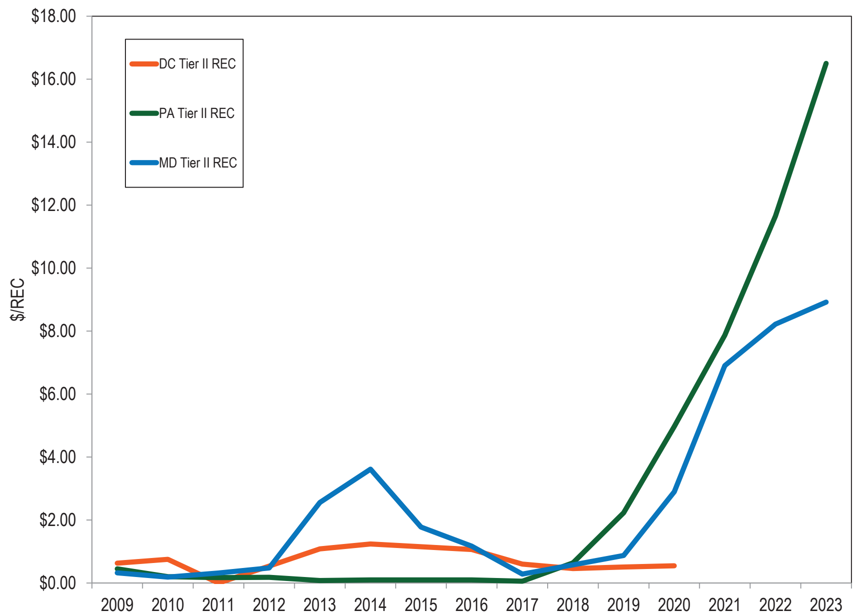
Jurisdiction	Type of Standard	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Maryland	Off Shore Wind	1.36%	2.03%	0.14%	1.66%	2.61%	13.02%	13.02%	13.02%	13.02%	13.02%	13.02%
Maryland	Geothermal	0.00%	0.05%	0.15%	0.25%	0.50%	0.75%	1.00%	1.00%	1.00%	1.00%	1.00%
Maryland	Tier 2	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%
New Jersey	Class II	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%
North Carolina	Swine Waste	0.14%	0.14%	0.20%	0.20%	0.20%	0.20%	0.20%	0.20%	0.20%	0.20%	0.20%
North Carolina	Poultry Waste (GWh)	900	900	900	900	900	900	900	900	900	900	900
Pennsylvania	Tier II	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%

189 Public Service Commission of Maryland, Offshore Wind Projects, Order No. 88192 (May 11, 2017) at 8, Table 2 <https://www.psc.state.md.us/wp-content/uploads/Order-No.-88192-Case-No.-9431-Offshore-Wind.pdf>.

190 The District of Columbia dropped Tier II RECs from their RPS in 2021.

191 Tier II REC price information obtained through Evolution Markets, Inc. <http://www.evomarkets.com>.

Figure 8-5 Average Tier II REC price by jurisdiction: 2009 through March 2023



Some PJM jurisdictions have specific solar resource RPS requirements. These solar requirements are included in the total requirements shown in Table 8-13 and Table 8-15 but must be met by solar RECs (SRECs). Table 8-18 shows the percent of retail electric load that must be served by solar energy resources under each PJM jurisdiction's RPS by year. Delaware, Illinois, Maryland, New Jersey, North Carolina, Pennsylvania, and Washington, DC have requirements for the proportion of load to be served by solar. The Illinois RPS specifies the number of RECs that must be sourced from photovoltaic resources energized after June 1, 2017. Recent legislation increased the SREC requirement from 2,000,000 RECs to 5,500,000 RECs beginning with the 2021/2022 Delivery Year.[192] New Jersey closed registration for new SRECs on April 30, 2020, having met its milestone that solar power equal or exceed 5.1 percent of New Jersey electricity sales.[193] On December 6, 2019, the New Jersey Board of Public Utilities announced a transitional program for solar generators not eligible for New Jersey SRECs.[194] The new program establishes a 15 year fixed priced Transition REC (TREC). On July 28, 2021, New Jersey Board of Public Utilities approved the Successor Solar Incentive (SuSI) Program which will provide incentives for 3,750 MW of new solar generation by 2026.[195] Pennsylvania allows only solar photovoltaic resources to fulfill their solar requirements. Solar thermal units like solar hot water heaters that do not generate electricity are Tier I resources in Pennsylvania. Ohio, Michigan and Virginia have no specific solar standards. The New Jersey legislature in May 2018 increased the solar standard from 3.2 percent to 4.3 percent for 2018, 5.1 percent for 2020 through 2022 and the solar standard decreases to 1.1 percent for 2032.[196] Maryland legislation in 2019 increased the solar carve out percentages from 2.5 percent to 14.5 percent in 2030. Ohio HB 6 removed the solar carve out from the Ohio RPS.[197] The Delaware General Assembly passed new RPS legislation on February 10, 2021 that increased the solar carve out target from 3.5 percent in 2025 to 10.0 percent in 2035.[198]

192 See amendments to Sec. 1-75(c)(1)(C) of the Illinois Power Agency Act contained in Section 90-30 of Public Act 102-0662.

193 See Clean Energy Act of 2019 (NJ AB-2723); N.J.A.C. 14:82.4(b)6; BPU, Monthly Report on Status toward Attainment of the 5.1 percent Milestone for Closure of the SREC Program (March 31, 2020).

194 "New Jersey Board of Public Utilities Approves Solar Transition Program, Initiates a Cost Cap Proceeding," New Jersey Board of Public Utilities Press Release (December 6, 2019) <https://www.bpu.state.nj.us/bpu/newsroom/2019/approved/20191206.html>.

195 "NJBPU Approves 3,750 MW Successor Solar Incentive Program", New Jersey Board of Public Utilities Press Release (July 28, 2021) <https://www.nj.gov/bpu/newsroom/2021/approved/20210728.html>.

196 "Assembly, No. 3723," State of New Jersey, 218th Legislature (March 22, 2018), <http://www.njleg.state.nj.us/2018/Bills/A4000/3723_I1.PDF>.

197 Ohio Legislature House, 133rd Assembly, Bill No. 6, "Ohio Clean Air Program," effective Date October 22, 2019, <https://www.legislature.ohio.gov/legislation/legislation-summary?id=GA133-HB-6>.

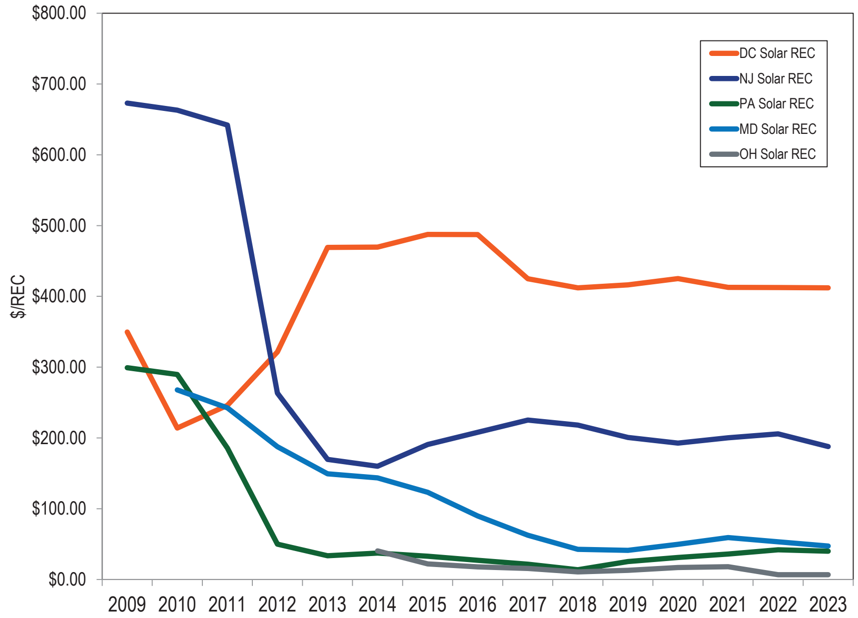
198 See Senate Bill 33, Delaware General Assembly (February 10, 2021) <https://legis.delaware.gov/BillDetail?legislationId=48278>.

Table 8-18 Solar renewable standards by percent of electric load for PJM jurisdictions: 2022 to 2032[199]

Jurisdiction with RPS	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Delaware	2.75%	3.00%	3.25%	3.50%	3.75%	4.00%	4.25%	4.50%	5.00%	5.80%	6.60%
Illinois (GWh)	5,500	5,500	5,500	5,500	5,500	5,500	5,500	5,500	24,750	24,750	24,750
Maryland	5.50%	6.00%	6.50%	7.00%	8.00%	9.50%	11.00%	12.50%	14.50%	14.50%	14.50%
New Jersey	5.10%	4.90%	4.80%	4.50%	4.35%	3.74%	3.07%	2.21%	1.58%	1.40%	1.10%
North Carolina	0.20%	0.20%	0.20%	0.20%	0.20%	0.20%	0.20%	0.20%	0.20%	0.20%	0.20%
Pennsylvania	0.50%	0.50%	0.50%	0.50%	0.50%	0.50%	0.50%	0.50%	0.50%	0.50%	0.50%
Washington, DC	2.60%	2.85%	3.15%	3.45%	3.75%	4.10%	4.50%	4.75%	5.00%	5.25%	5.50%

Figure 8-6 shows the average solar REC (SREC) price by jurisdiction for January 1, 2009, through March 31, 2023. The average NJ SREC price was $187.78 for the first three months of 2023. The limited supply of solar facilities in Washington, DC compared to the RPS requirement results in higher SREC prices. The average Washington, DC SREC price was $411.94 per SREC for the first three months of 2023.[200]

Figure 8-6 Average SREC price by jurisdiction: 2009 through March 2023



199 The Illinois solar standard currently requires 5.5 million RECs from solar photovoltaic projects energized after June 1, 2017. Illinois Public Act 102-0662, September 15, 2021.
200 Solar REC average price information obtained through Evolution Markets, Inc. <http://www.evomarkets.com> (Accessed April 18, 2022).

Figure 8-7 and Table 8-19 show where the SRECs originated that are used to satisfy the states' solar requirement for 2017 through 2022.[201] Depending on the state, the solar RPS requirement can be fulfilled by in state or out of state SRECs. The SRECs purchased in some states are imported from other PJM states and from non PJM states. Table 8-19 shows the percent of imported and local SRECs used to meet the RPS requirements. Since 2020, all SRECs used for RPS compliance in Illinois, Maryland, Pennsylvania and New Jersey have been sourced from in state solar generators.

Figure 8-7 State fulfillment of Solar RPS: 2017 through 2022

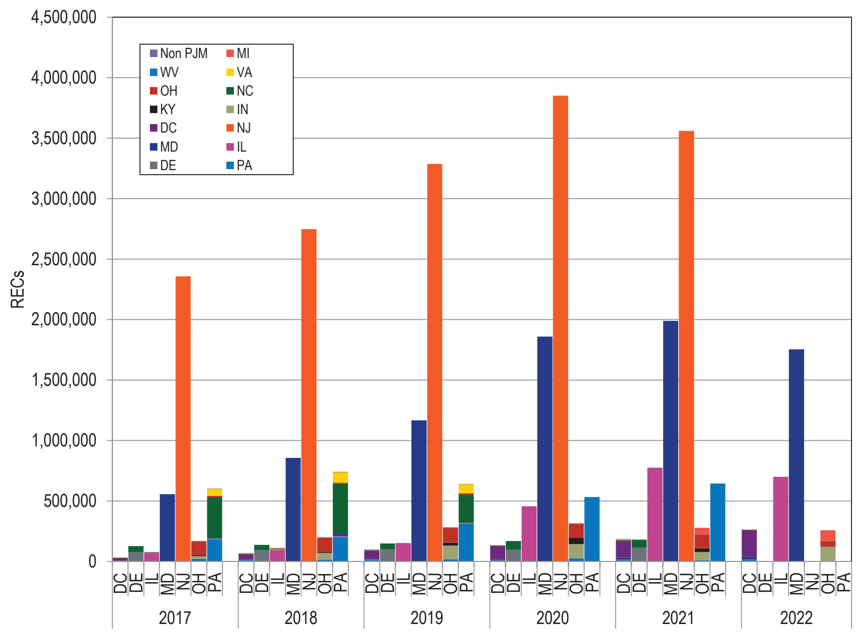


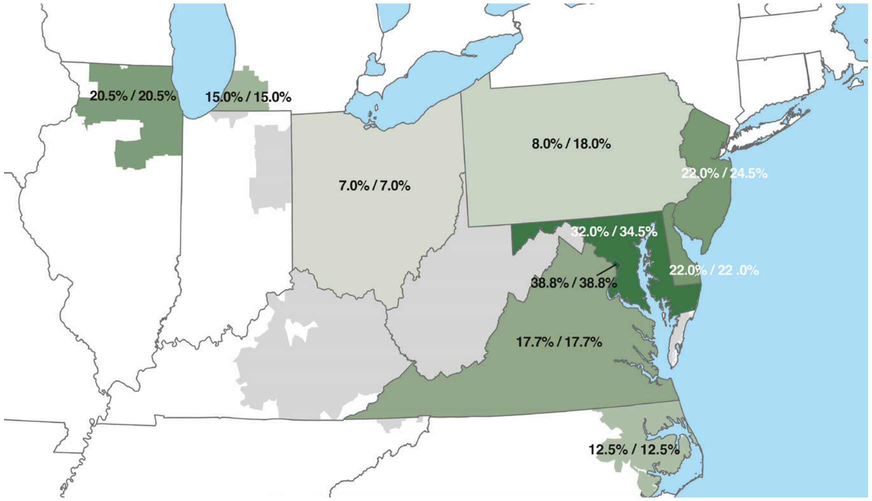
Table 8-19 State fulfillment of Solar RPS: 2017 through 2022

		In State SREC	Import SREC
2017	DC Solar	63.8%	36.2%
	DE Solar Eligible	61.9%	38.1%
	IL Solar Renewable	87.6%	12.4%
	MD Solar	100.0%	0.0%
	NJ Solar	100.0%	0.0%
	OH Solar Renewable Energy Source	69.0%	31.0%
	PA Solar	30.6%	69.4%
2018	DC Solar	67.4%	32.6%
	DE Solar Eligible	67.7%	32.3%
	IL Solar Renewable	82.9%	17.1%
	MD Solar	100.0%	0.0%
	NJ Solar	100.0%	0.0%
	OH Solar Renewable Energy Source	59.5%	40.5%
	PA Solar	27.1%	72.9%
2019	DC Solar	72.4%	27.6%
	DE Solar Eligible	67.8%	32.2%
	IL Solar Renewable	100.0%	0.0%
	MD Solar	100.0%	0.0%
	NJ Solar	100.0%	0.0%
	OH Solar Renewable Energy Source	43.6%	56.4%
	PA Solar	48.8%	51.2%
2020	DC Solar	81.5%	18.5%
	DE Solar Eligible	56.7%	43.3%
	IL Solar Renewable	100.0%	0.0%
	MD Solar	100.0%	0.0%
	NJ Solar	100.0%	0.0%
	OH Solar Renewable Energy Source	36.8%	63.2%
	PA Solar	100.0%	0.0%
2021	DC Solar	78.0%	22.0%
	DE Solar Eligible	62.3%	37.7%
	IL Solar Renewable	100.0%	0.0%
	MD Solar	100.0%	0.0%
	NJ Solar	100.0%	0.0%
	OH Solar Renewable Energy Source	40.2%	59.8%
	PA Solar	100.0%	0.0%
2022	DC Solar	81.9%	18.1%
	DE Solar Eligible		
	IL Solar Renewable	100.0%	0.0%
	MD Solar	100.0%	0.0%
	NJ Solar		
	OH Solar Renewable Energy Source	17.4%	82.6%
	PA Solar	100.0%	0.0%

201 Retired REC information obtained through PJM GATS <https://gats.pjm-eis.com/gats2/PublicReports/RPSRetiredCertificatesReportingYear> (Accessed January 23, 2023). The timing of the REC retirement reports varies by state and the 2021 reporting year data may be incomplete for some states.

Figure 8-8 shows the percent of retail electric load that must be served by Tier I resources and Tier 2 resources in each PJM jurisdiction with a mandatory RPS. For each state in Figure 8-8, the first number represents the RPS percent for Tier I or renewable energy resources; the second number represents the RPS percent for all eligible technologies which includes both renewable and alternative energy resources. States with higher percent requirements for renewable energy resources are shaded darker. Jurisdictions with no standards or with only voluntary RPS are shaded gray. Pennsylvania's RPS illustrates the need to differentiate between percent requirements for renewable and alternative energy resources. The Pennsylvania RPS identifies solar photovoltaic, solar thermal, wind, geothermal, biomass, and low-impact hydropower as Tier I resources. The Pennsylvania RPS identifies waste coal, demand side management, large-scale hydropower, integrated gasification combined cycle, clean coal and municipal solid waste as eligible Tier II resources. As a result, the 18.0 percent number in Figure 8-8 overstates the percent of retail electric load in Pennsylvania that must be served by renewable energy resources. The 8.0 percent number in Figure 8-8 is a more accurate measure of the percent of retail electric load in Pennsylvania that must be served by renewable energy resources.

Figure 8-8 Map of retail electric load shares under RPS – Renewable / Alternative Energy resources: 2023[202]



Under the existing state renewable portfolio standards, 16.2 percent of PJM load should have been served by Tier I and Tier II renewable and alternative energy resources in the first three months of 2023. Tier I resources include landfill gas, run of river hydro, wind and solar resources. Tier II resources include pumped storage, large scale hydro, solid waste and waste coal resources. In the first three months of 2023, only 8.1 percent of PJM generation was renewable and alternative energy resources, including carbon producing and noncarbon producing Tier I and Tier II generation as shown in Table 8-20. If the proportion of load among states remains constant, 25.5 percent of PJM load must be served by Tier I and Tier II renewable and alternative energy resources in 2030 under currently defined RPS rules. Approximately 13.8 percent of PJM load should have been served by Tier I or renewable energy resources in in the first three months of 2023. In the first three months of 2023, only 5.8 percent of PJM generation was Tier I or renewable energy. The current REC production from PJM generation resources was not enough to meet the state renewable requirements for the first three months of 2023,

202 The standards in this chart include the Tier I standards used by some states in the PJM footprint, as well as the total alternative energy standard for states that do not classify eligible technologies into tiers.

and LSEs purchased RECs from non PJM resources (e.g. behind the meter rooftop solar) and RECs from resources outside the PJM footprint (Table 8-21). LSEs that are unable to meet the RPS with RECs may use alternative compliance payments for unmet goals based on each state's requirements. If the proportion of load among states remains constant, 23.1 percent of PJM load must be served by Tier I or renewable energy resources in 2030 under defined RPS rules.

In jurisdictions with an RPS, load serving entities must either generate power from eligible technologies identified in each jurisdiction's RPS or purchase RECs from resources classified as eligible technologies. Table 8-20 shows generation by jurisdiction and resource type for the first three months of 2023. Wind generation accounted for 9,928.7 GWh of the 15,102.2 Tier I GWh, or 65.7 percent. As shown in Table 8-20, 18,946.2 GWh were generated by Tier I and Tier II resources, of which Tier I resources were 79.7 percent. Wind and solar generation (noncarbon producing) was 5.8 percent of total generation in PJM in the first three months of 2023. Tier I generation was 7.4 percent of total generation in PJM and Tier II was 1.9 percent of total generation in PJM in the first three months of 2023. Biofuel, landfill gas, pumped storage hydro, solid waste and waste coal (carbon producing) accounted for 4,199.7 GWh, or 22.2 percent of the total Tier I and Tier II generation.

Table 8-20 Tier I and Tier II generation by jurisdiction and renewable resource type (GWh): January through March, 2023

	Tier I							Tier II					
Jurisdiction	Biofuel	Landfill Gas	Run of River	Other Hydro	Solar	Wind	Total Tier I Credit	Pumped-Storage Hydro	Other Hydro	Solid Waste	Waste Coal	Total Tier II Credit	Total Credit GWh
Delaware	0.0	11.0	0.0	0.0	16.3	0.0	27.4	0.0	0.0	0.0	0.0	0.0	27.4
Illinois	0.0	19.0	0.0	0.0	1.9	4,525.1	4,546.1	0.0	0.0	0.0	0.0	0.0	4,546.1
Indiana	0.0	0.2	0.0	10.6	116.8	2,180.8	2,308.4	0.0	0.0	0.0	0.0	0.0	2,308.4
Kentucky	0.0	0.0	55.8	15.3	18.9	0.0	90.0	0.0	0.0	0.0	0.0	0.0	90.0
Maryland	0.0	10.8	0.0	0.0	131.1	237.1	379.0	0.0	0.0	130.2	0.0	130.2	509.2
Michigan	0.0	14.8	0.0	17.1	1.0	0.0	32.8	0.0	0.0	0.0	0.0	0.0	32.8
New Jersey	0.0	34.5	3.6	0.0	168.7	3.7	210.5	67.0	0.0	292.2	0.0	359.2	569.7
North Carolina	0.0	0.0	137.0	0.0	401.4	170.9	709.3	0.0	0.0	0.0	0.0	0.0	709.3
Ohio	0.0	28.0	232.8	0.0	159.3	929.1	1,349.2	0.0	0.0	0.0	0.0	0.0	1,349.2
Pennsylvania	0.0	89.7	1,602.5	8.8	51.8	1,185.1	2,937.8	578.3	0.0	380.9	1,226.8	2,186.0	5,123.8
Tennessee	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Virginia	297.5	113.8	264.0	19.6	870.5	15.6	1,581.0	567.5	271.2	174.5	0.0	1,013.3	2,594.3
Washington, D.C.	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
West Virginia	0.0	7.6	235.3	0.0	6.5	681.3	930.6	0.0	0.0	0.0	155.4	155.4	1,086.0
Total	297.5	329.4	2,531.0	71.3	1,944.3	9,928.7	15,102.2	1,212.8	271.2	977.8	1,382.2	3,844.0	18,946.2

PJM states with RPS rely heavily on imports and generation from behind the meter resources for RPS compliance. In the first three months of 2023, Tier I generation in PJM met only 58.4 percent of the Tier I RPS requirements. Table 8-21 compares each state's RPS requirement for the first three months of 2023 with generation by RPS eligible PJM generators. Illinois had sufficient in state generation to cover 101.1 percent of the RPS requirement and Pennsylvania generation was sufficient to cover 99.1 percent of the Tier I RPS requirement and 59.0 percent of the Tier II RPS requirement. North Carolina generation was in excess of the RPS requirement but a relatively small portion of the North Carolina load is in PJM. Overall there was sufficient generation in PJM states to meet 58.4 percent of the Tier I RPS requirement and 85.3 percent of the Tier II RPS requirement for the first three months of 2023.

Table 8-21 RPS Requirements and Generation by RPS Eligible Resources: January through March, 2023

	Tier I			Tier II		
Jurisdiction	PJM Generation (GWh)	RPS Requirement (GWh)	Generation as Percent of RPS Requirement	PJM Generation (GWh)	RPS Requirement (GWh)	Generation as Percent of RPS Requirement
Delaware	27.4	634.2	4.3%	0.0	0.0	
Illinois	4,546.1	4,498.8	101.1%	0.0	0.0	
Indiana	2,308.4	0.0		0.0	0.0	
Kentucky	90.0	0.0		0.0	0.0	
Maryland	379.0	4,804.3	7.9%	130.2	375.9	34.6%
Michigan	32.8	166.4	19.7%	0.0	0.0	
New Jersey	210.5	3,742.2	5.6%	359.2	425.3	84.5%
North Carolina	709.3	130.2	544.7%	0.0	0.0	
Ohio	1,349.2	2,633.1	51.2%	0.0	0.0	
Pennsylvania	2,937.8	2,964.0	99.1%	2,186.0	3,705.0	59.0%
Tennessee	0.0	0.0		0.0	0.0	
Virginia	1,581.0	5,453.3	29.0%	1,013.3	0.0	
Washington, D.C.	0.0	814.1	0.0%	0.0	0.0	
West Virginia	930.6	0.0		155.4	0.0	
Total	15,102.2	25,840.7	58.4%	3,844.0	4,506.2	85.3%

Table 8-22 shows the summer installed capacity rating of Tier I and Tier II wholesale capacity resources in PJM by jurisdiction, as defined by primary fuel type. This capacity includes coal, natural gas and oil units that qualify as Tier II because they have a secondary fuel capability that satisfies the alternative energy standards of a PJM state or jurisdiction. For example, a coal generator that can also burn waste coal to generate power could list the alternative fuel as waste coal. A REC is only generated when the unit is operating using the fuel listed as Tier I or Tier II. Virginia has the largest amount of solar capacity in PJM, 2,841.1 MW, or 40.7 percent of the total solar capacity. Wind resources located in western PJM, Illinois, Indiana and Ohio, account for 8,122.1 MW, or 73.9 percent of the total wind capacity.

Under the pre ELCC rules that remain in effect until the start of the 2023/2024 delivery year, a generator's capacity value was derated from the installed capacity level by multiplying the generator's net maximum capability by a derating factor. The derating factor was either based on the generator's historical performance during summer peak hours or a class average value calculated by PJM. The intent of the pre ELCC method was to obtain a MW value the generator can reliably produce during the summer peak hours.[203] As of March 31, 2022, the derated capacity with capacity obligations in the PJM Capacity Market totaled 3,501.1 MW for wind generators and 2,790.5 MW for solar generators. This compares to installed wind capacity of 10,995.8 MW and installed solar capacity of 6,985.3 MW in Table 8-22. Wind generators have higher derating factors during the winter months (November through April) because PJM rules make winter capacity interconnection rights (CIRs) available. PJM posts class average capacity factors for wind and solar generators. There were two pre ELCC classes of wind based on location with class average capacity factors of 14.7 percent and 17.6 percent.[204]

203 See Appendix B in "PJM Manual 21: Rules and Procedures for Determination of Generating Capability," <https://pjm.com/-/media/documents/manuals/m21.ashx>.
204 See "Class Average Capacity Factors Wind and Solar Resources," PJM, June 1, 2017. PJM has removed this document from its web page.

Table 8-22 Renewable capacity by jurisdiction (MW): March 31, 2023

Jurisdiction	Biofuel	Coal / Biofuel	Hydro	Landfill Gas	Natural Gas / Landfill Gas	Other Gas	Oil / Biofuel	Oil / Landfill Gas	Pumped-Storage Hydro	Solar	Solid Waste	Waste Coal	Waste Heat	Wind	Total
Delaware	0.0	0.0	0.0	8.1	1,797.0	0.0	0.0	13.0	0.0	50.0	0.0	0.0	0.0	0.0	1,868.1
Illinois	0.0	0.0	0.0	15.0	0.0	0.0	0.0	0.0	0.0	9.0	0.0	0.0	0.0	4,726.1	4,750.1
Indiana	0.0	0.0	8.2	3.2	0.0	0.0	0.0	0.0	0.0	454.2	0.0	0.0	0.0	2,350.5	2,816.0
Kentucky	0.0	0.0	132.7	0.0	0.0	0.0	0.0	0.0	0.0	69.6	0.0	0.0	0.0	0.0	202.3
Maryland	0.0	0.0	0.0	19.9	0.0	0.0	69.0	0.0	0.0	486.5	128.2	0.0	0.0	243.7	947.3
Michigan	0.0	0.0	13.9	12.0	0.0	0.0	0.0	0.0	0.0	4.6	0.0	0.0	0.0	0.0	30.5
Missouri	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	146.0	146.0
New Jersey	0.0	0.0	11.0	33.9	0.0	0.0	0.0	0.0	453.0	739.8	204.6	0.0	0.0	4.5	1,446.7
North Carolina	0.0	0.0	325.0	0.0	0.0	0.0	0.0	0.0	0.0	1,331.6	0.0	0.0	0.0	208.0	1,864.6
Ohio	0.0	1,020.0	194.4	30.4	0.0	1.0	136.0	0.0	0.0	798.9	0.0	0.0	134.0	1,045.6	3,360.3
Pennsylvania	54.0	0.0	1,387.3	122.0	1,300.0	0.0	0.0	0.0	1,269.0	170.9	209.3	1,347.0	0.0	1,457.2	7,316.7
Tennessee	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Virginia	241.9	585.0	436.4	127.7	0.0	88.0	17.0	0.0	5,386.0	2,841.1	123.0	0.0	0.0	12.0	9,858.1
Washington, D.C.	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
West Virginia	0.0	0.0	209.9	8.0	0.0	0.0	0.0	0.0	0.0	29.1	0.0	96.0	0.0	802.3	1,145.2
PJM Total	295.9	1,605.0	2,718.7	380.1	3,097.0	89.0	222.0	13.0	7,108.0	6,985.3	665.0	1,443.0	134.0	10,995.8	35,751.8

There were three pre ELCC classes of solar generators with capacity factors ranging from 38.0 percent to 60.0 percent.[205] For the 2023/2024 Delivery Year, the ELCC rating for solar generators with fixed panels is 38.0 percent and the ELCC rating for solar generators with tracking panels is 54.0 percent.

Table 8-23 shows renewable capacity registered in the PJM generation attribute tracking system (GATS).[206] These resources are not PJM resources even though most are located in PJM states. For example, roof top solar panels within the PJM footprint generate SRECs but are not PJM units. This includes solar capacity of 9,698.3 MW of which 3,290.5 MW are in New Jersey. These resources can earn renewable energy credits, and can be used to fulfill the renewable portfolio standards in PJM jurisdictions. There are 1,774.7 MW of GATS capacity located in jurisdictions outside PJM and all but 242.6 MW are eligible to produce RECs in at least one PJM jurisdiction.

205 Id.
206 PJM Environmental Information Services (EIS), an unregulated subsidiary of PJM, operates the generation attribute tracking system (GATS), which is used by many jurisdictions to track these renewable energy credits. GATS publishes details on every renewable generator registered within the PJM footprint and aggregate emissions of renewable generation, but does not publish generation data by unit and does not make unit data available to the MMU.

Table 8-23 Renewable capacity by jurisdiction, non-PJM units registered in GATS (MW): March 31, 2023[207]

Jurisdiction	Biofuel	Coal / Biofuel	Fuel Cell	Geothermal	Hydro	Landfill Gas	Natural Gas / Distributed Generation	Other Gas	Solar	Solid Waste	Waste Coal	Waste Heat	Wind	Total
Alabama	54.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	54.0
Delaware	0.0	0.0	0.0	0.0	0.0	2.2	0.0	0.0	151.3	0.0	0.0	0.0	2.0	155.5
Georgia	0.0	0.0	0.0	0.0	0.0	27.1	0.0	0.0	152.2	0.0	0.0	0.0	0.0	179.3
Illinois	0.0	0.0	0.0	0.0	20.0	50.6	0.0	2.2	1,092.3	0.0	0.0	0.0	398.4	1,563.4
Indiana	0.0	0.0	0.0	0.0	0.0	47.2	0.0	1.3	175.8	0.0	0.0	94.6	180.0	498.9
Iowa	0.0	0.0	0.0	0.0	0.0	1.6	0.0	0.0	2.1	0.0	0.0	0.0	336.8	340.5
Kentucky	93.0	600.0	0.0	0.0	164.8	20.2	0.0	0.0	39.3	0.0	0.0	0.0	0.0	917.3
Maryland	18.5	0.0	0.0	27.5	0.4	14.7	0.0	0.0	1,387.8	10.0	0.0	0.0	0.3	1,459.1
Michigan	31.0	0.0	0.0	0.0	17.2	16.6	0.0	4.8	113.9	0.0	0.0	0.0	87.4	270.8
Minnesota	0.0	0.0	0.0	0.0	36.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	36.0
Missouri	0.0	0.0	0.0	0.0	0.0	5.6	0.0	0.0	61.2	0.0	0.0	0.0	693.0	759.8
New Jersey	0.0	0.0	0.0	0.0	0.0	23.5	0.0	15.4	3,290.5	0.0	0.0	0.0	3.1	3,332.5
New York	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.4	0.0	0.0	0.0	0.0	0.4
North Carolina	151.5	0.0	0.0	0.0	800.4	0.0	0.0	0.0	1,283.1	0.0	0.0	0.0	0.0	2,235.0
North Dakota	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	360.0	360.0
Ohio	92.8	0.0	0.0	0.0	6.6	19.7	0.0	49.3	303.2	0.0	0.0	34.0	53.3	558.9
Pennsylvania	62.2	109.7	0.8	0.0	56.5	45.2	22.1	100.0	692.6	0.2	474.2	57.6	3.2	1,624.3
South Carolina	0.0	0.0	0.0	0.0	31.5	29.8	0.0	0.0	91.3	0.0	0.0	0.0	0.0	152.6
Tennessee	0.0	0.0	0.0	0.0	411.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	411.6
Virginia	287.6	0.0	0.0	0.0	31.3	9.9	0.0	2.6	664.4	0.0	0.0	0.0	0.0	995.8
Washington, D.C.	0.0	0.0	0.0	0.0	0.0	0.0	0.0	49.4	188.9	0.0	0.0	27.7	0.0	266.1
West Virginia	0.0	0.0	0.0	0.0	102.0	0.0	0.0	0.0	7.7	0.0	0.0	0.0	0.0	109.7
Wisconsin	44.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.0	0.0	0.0	0.0	44.7
Total	835.1	709.7	0.8	27.5	1,678.3	313.9	22.1	224.8	9,698.3	10.2	474.2	213.9	2,117.4	16,326.4

Renewable energy credits are related to the production and purchase of wholesale power, but are not, when they constitute a transaction separate from a wholesale sale of power, subject to FERC regulation.[208] RECs markets are, as an economic fact, integrated with PJM markets including energy and capacity markets, but are not formally recognized as part of PJM markets. Revenues from RECs markets are revenues for PJM resources earned in addition to revenues earned from the sale of the same MWh in PJM markets. RECs revenues are included in net revenues in unit offers in the capacity market and the treatment of RECs in unit cost-based offers is included in unit fuel cost policies.

Delaware, North Carolina, Michigan and Virginia allow various types of resources to earn multiple RECs per MWh, though typically one REC is equal to one MWh. For example, Delaware provided a three MWh REC for each MWh produced by in-state customer sited photovoltaic generation and fuel cells using renewable fuels that are installed on or before December 31, 2014.[209] This is equivalent to providing a REC price equal to three times its stated value per MWh.

207 See PJM-EIS (Environmental Information Services), Generation Attribute Tracking System, "Renewable Generators Registered in GATS," <https://gats.pjm-eis.com/gats2/PublicReports/RenewableGeneratorsRegisteredinGATS> (Accessed July 20, 2022).
208 See *WSPP, Inc.*, 139 FERC ¶ 61,051 at P 18 (2012) ("we conclude that unbundled REC transactions fall outside of the Commission's jurisdiction under sections 201, 205 and 206 of the FPA. We further conclude that bundled REC transactions fall within the Commission's jurisdiction under sections 201, 205 and 206 of the FPA"); citing *American Ref-Fuel Company, et al.*, 105 FERC ¶ 61,004 at PP 23–24 (2003) ("American Ref-Fuel, 105 FERC ¶ 61,004 at PP 23-24 ("RECs are created by the States. They exist outside the confines of PURPA... And the contracts for sales of QF capacity and energy, entered into pursuant to PURPA, ... do not control the ownership of RECs."); see also *Williams Solar LLC and Allco Finance Limited*, 156 FERC ¶ 61,042 (2016).
209 See DSIRE, NC Clean Energy Technology Center. Delaware Renewable Portfolio Standard, <http://programs.dsireusa.org/system/program/detail/1231> (Accessed November 3, 2018).

In addition to GATS, there are several other REC tracking systems used by states in the PJM footprint. Illinois, Indiana and Ohio use both GATS and M-RETS, the REC tracking system for resources located in the Midcontinent ISO, to track the sales of RECs used to fulfill their RPS requirements. Michigan and North Carolina have created their own state-wide tracking systems, MIRECS and NC-RETS, through which all RECs used to satisfy these states' RPS requirements must ultimately be traded. Table 8-24 shows the REC tracking systems used by each state within the PJM footprint. To ensure a REC is only used one time, REC tracking systems must keep an account of a REC from its creation until its retirement. A REC is considered to be retired when it has been used to satisfy an obligation associated with an RPS.

Table 8-24 REC tracking systems in PJM states with renewable portfolio standards

Jurisdiction with RPS	REC Tracking System Used			
Delaware	PJM-GATS			
Illinois	PJM-GATS	M-RETS		
Maryland	PJM-GATS			
Michigan			MIRECS	
New Jersey	PJM-GATS			
North Carolina				NC-RETS
Ohio	PJM-GATS	M-RETS		
Pennsylvania	PJM-GATS			
Virginia	PJM-GATS			
Washington, D.C.	PJM-GATS			
Jurisdiction with Voluntary Standard				
Indiana	PJM-GATS	M-RETS		

All PJM states with renewable portfolio standards have specified geographical restrictions governing the source of RECs to satisfy states' standards. Table 8-25 describes these restrictions. Indiana, Illinois, Michigan, and Ohio all have provisions in their renewables standards that require all or a portion of RECs used to comply with each state's standards to be generated by in-state resources. Illinois recently relaxed the geographic restrictions to allow RECs sourced from wind or photovoltaic resources that are deliverable to Illinois or an adjacent state via high voltage direct current transmission. North Carolina has provisions that require RECs to be purchased from in-state resources but Dominion, the only utility located in both North Carolina and PJM, is exempt from these provisions. Pennsylvania added a provision in 2017 that requires SRECs used to comply with Pennsylvania's solar photovoltaics carve out standard to be sourced from resources located in Pennsylvania.

Pennsylvania and Virginia require that RECs used for RPS compliance be produced from resources located within the PJM footprint. Delaware requires that RECs used for compliance with its RPS are produced from resources located within the PJM footprint or resources located elsewhere if these resources can demonstrate that the power they produce is directly deliverable to Delaware. The District of Columbia, Maryland and New Jersey allow RECs to be purchased from resources located within PJM in addition to large areas that adjoin PJM for compliance with their standards.

Table 8-25 Geographic restrictions on REC purchases for renewable portfolio standard compliance in PJM states

State with RPS	RPS Contains In-state Provision	Geographical Requirements for RPS Compliance
Delaware	No	RECs must be purchased from resources located either within PJM or from resources outside of PJM that are directly deliverable into Delaware.
Illinois	Yes	All RECs must be purchased from resources located within Illinois or from resources located in adjacent states that meet certain public interest criteria or from utility scale wind or photovoltaic resources that are deliverable to Illinois or an adjacent state via high voltage direct current transmission.
Maryland	No	RECs must come from within PJM, 10-30 miles offshore the coast of Maryland or from a control area adjacent to PJM that is capable of delivering power into PJM.
Michigan	Yes	RECs must either come from resources located within Michigan or anywhere in the service territory of retail electric provider in Michigan that is not an alternative electric supplier. There are many exceptions to these requirements (see Michigan S.B. 213).
New Jersey	No	RECs must either be purchased from resources located within PJM or from resources located outside of PJM for which the energy associated with the REC is delivered to PJM via dynamic scheduling.
North Carolina	Yes	Dominion, the only utility located in both the state of North Carolina and PJM, may purchase RECs from anywhere. Other utilities in North Carolina not located in PJM are subject to different REC requirements (see G.S. 62-113.8).
Ohio	Yes	All RECs must be generated from resources that are located in the state of Ohio or have the capability to deliver power directly into Ohio. Any renewable facility located in a state contiguous to Ohio has been deemed deliverable into the state of Ohio. For renewable resources in noncontiguous states, deliverabilty must be demonstarted to the Public Utilities Commission of Ohio.
Pennsylvania	Yes	RECs must be purchased from resources located within PJM. All SRECs used for compliance with the Solar PV standard must source from solar PV resources within the state of Pennsylvania.
Virginia	No	RECs must be purchased from resources located within PJM
Washington, D.C.	No	RECs must be purchased from either a PJM state or a state adjacent with PJM. A PJM state is defined as any state with a portion of their geographical boundary within the footprint of PJM. An adjacent state is defined as a state that lies next to a PJM state, i.e. SC, GA, AL, AR, IA, NY, MO, MS, and WI.

Alternative Compliance Payments

PJM jurisdictions have various methods for enforcing compliance with required renewable portfolio standards. If a retail supplier is unable to comply with the renewable portfolio standards required by the jurisdiction, suppliers may make alternative compliance payments (ACPs), with varying standards, to cover any shortfall between the RECs required by the state and those the retail supplier actually purchased. The ACPs, which are penalties, function as a cap on the market value of RECs. In New Jersey, solar ACPs are currently $228.00 per MWh.[210] Pennsylvania requires that solar ACPs be 200 percent of the average credit price of Pennsylvania solar RECs sold during the reporting year plus the value of any solar rebates. The most recent ACP for Pennsylvania solar is $82.90.[211] Delaware recently reduced the solar ACP from $400 per credit to $150 per credit.[212] Maryland reduced the solar ACP from $100 per credit to $80 per credit effective June 1, 2021.[213]

Figure 8-9 shows the historical relationship between SREC prices and ACP levels. The SREC price is represented by a solid line in the figure and the corresponding ACP level is represented by a dashed line. For each jurisdiction, the ACP is an upper bound for the price level. In Michigan and North Carolina, there are no defined values for ACPs. The public utility commissions in Michigan and North Carolina have discretionary power to assess what a load serving entity must pay for any RPS shortfalls.

Table 8-26 shows the alternative compliance standards for RPS in PJM jurisdictions.

210 N.J. S. 2314/A. 3723.
211 See AEPS History Pricing report at the AEPS website <https://pennaeps.com/reports/> (Accessed October 20, 2022).
212 See Senate Bill 33, Delaware General Assembly (February 10, 2021) <https://legis.delaware.gov/BillDetail?legislationId=48278>.
213 *Senate Bill 65 Electricity – Renewable Energy Portfolio Standard – Tier 2 Renewable Sources, Qualifying Biomass, and Compliance Fees*, Maryland General Assemble (2021) <https://mgaleg.maryland.gov/mgawebsite/Legislation/Details/sb0065?ys=2021RS>.

Table 8-26 Tier I, Tier II, and Solar alternative compliance payments in PJM jurisdictions as of March 31, 2023[214 215]

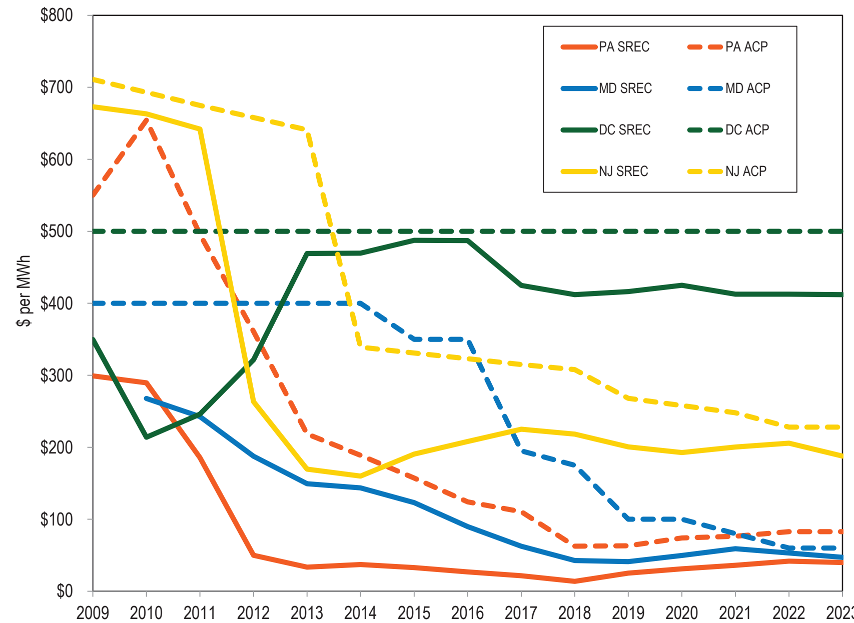
Jurisdiction with RPS	Standard Alternative Compliance ($/MWh)	Tier II Alternative Compliance ($/MWh)	Solar Alternative Compliance ($/MWh)
Delaware	$25.00		$150.00
Illinois	$0.35		
Maryland	$30.00	$15.00	$60.00
Michigan	No specific penalties		
New Jersey	$50.00	$50.00	$228.00
North Carolina	No specific penalties: At the discretion of the NC Utility Commission		
Ohio	$56.99		
Pennsylvania	$45.00	$45.00	$82.90
Washington, D.C.	$50.00	$10.00	$500.00
Jurisdiction with Voluntary Standard			
Indiana	Voluntary standard - No Penalties		
Virginia	Voluntary standard - No Penalties		
Jurisdiction with No Standard			
Kentucky	No standard		
Tennessee	No standard		
West Virginia	No standard		

Load serving entities participating in mandatory RPS programs in PJM jurisdictions must submit compliance reports to the relevant jurisdiction's public utility commission.

214 The Ohio standard alternative compliance payment (ACP) is updated annually <https://www.puco.ohio.gov/industry-information/industry-topics/acp-non-solar-alternative-compliance-payment-under-orc-492864/>. The Illinois Commerce Commission periodically publishes updates to the effective ACP amount <https://www.icc.illinois.gov/electricity/RPSCompliancePaymentNotices.aspx>. For updated Maryland ACPs, see Table 3 of the 2018 Renewable Energy Portfolio Standard Report <https://www.psc.state.md.us/commission-reports/>.

215 The entry for Pennsylvania reflects the solar ACP for the compliance year ending May 31, 2021. See "Pricing," <https://www.pennaeps.com/reports/> (Accessed January 26, 2022).

Figure 8-9 Comparison of SREC price and solar ACP: 2009 through March 2023



In their submitted compliance reports, load serving entities must indicate the quantity of MWh that they have generated using eligible renewable or alternative energy resources. They must also identify the quantity of RECs they may have purchased to make up for renewable energy generation shortfalls or to comply with RPS provisions requiring that they purchase RECs. The public utility commissions then release RPS compliance reports to the public.

The Pennsylvania Public Utility Commission issued their 2022 compliance report for the Pennsylvania Alternative Energy Standards Act of 2004 in March of 2023.[216] Pennsylvania reported that the 694,980 SRECs, 10,891,729 Tier I RECs and 13,895,805 Tier II RECs were retired during the 2022 reporting

216 "Alternative Energy Portfolio Standards Act of 2004 Compliance for Reporting Year 2022," (March 2023), <https://www.puc.pa.gov/filing-resources/reports/alternative-energy-portfolio-standards-aeps-reports/>

year (June 1, 2021 through May 31, 2022). Supplier obligations for 598 SRECs, 11,999 Tier I RECs and 15,310 Tier II RECs required ACPs.

The Public Service Commission of the District of Columbia reported that 183,707 SRECs and 2,173,550 Tier I RECs were retired during the 2021 compliance year. The average price for solar RECs was $430.94. ACPs decreased from $8.2 million for 2020 to $5.7 million for 2021.[217]

The Public Service Commission of Maryland reported that 1,989,505 SRECs were retired in 2021, an increase of 7.0 percent over the 2020 level. Tier 1 REC retirements increased to 13,045,432, 7.7 percent higher than in 2020.[218] ACPs increased significantly, from $52,240 in 2020 to $77,129,013 for 2021, as a result of the requirement to purchase SRECs and a shortfall in available SRECs. [219] The ACP level in in 2020 was $52,240.

The Public Utilities Commission of Ohio reported that 6,023,768 RECs were retired in the 2020 compliance year, which is 4,000 RECs short of the RPS requirement. Alternative compliance payments were made due to the shortfall.[220]

Delmarva Power is the only retail electric supplier that must file a compliance report with the Delaware Public Service Commission. Delmarva Power reported to the Delaware Public Service Commission that they satisfied their REC obligation of 740,604 credits for the compliance year ending May 31, 2021, with zero ACPs.[221] Delmarva Power satisfied their solar REC obligation of 150,262 credits with zero alternative compliance payments.

Prior to the 2017/2018 compliance year, the Illinois RPS had required electricity suppliers to satisfy at least 50 percent of their RPS obligation through ACPs. This requirement was removed for the 2017/2018 compliance year and ACPs for ComEd decreased to $74,148. The ACPs for ComEd in compliance year 2016/2017 totaled $40,575,311.[222]

The North Carolina Utilities Commission reported that Dominion North Carolina Power submitted its 2018 compliance report on August 13, 2019. The compliance report stated that Dominion met its general RPS requirement by purchasing 397,643 credits that consisted of wind and hydro RECs and energy efficiency credits (EECs).[223] Dominion also met its solar, poultry waste, and swine waste requirements by purchasing RECs.

The Michigan Public Service Commission reported that Indiana Michigan Power Company met the 2018 standard by generating or acquiring 283,473 RECs.[224]

New Jersey's Office of Clean Energy posted a summary of RPS compliance through the energy year ending May 31, 2021.[225] Electric power suppliers retired 11,638,713 class I RECs and 1,803,748 class II RECs. Suppliers submitted 1,892 class I ACPs and 986 class II ACPs at a cost of $50 per MWh. Electric power suppliers retired 3,851,012 solar RECs and 12 SACPs were submitted at a cost of $248 per MWh. Additionally, 128,356 transition RECs were retired.[226]

Table 8-27 shows the RPS compliance cost incurred by PJM jurisdictions as reported by the jurisdictions.[227] The compliance costs are the cost of acquiring RECs plus the cost of any alternative compliance payments. The cost of complying with RPS, as reported by the states, was $7.2 billion over the seven year period from 2014 through 2020 for the nine jurisdictions that had RPS and reported compliance costs.[228] The average RPS compliance cost per year

217 "Renewable Energy Portfolio Standard, A Report for Compliance Year 2021," Public Service Commission of the District of Columbia (May 2, 2022), <https://dcpsc.org/Orders-and-Regulations/PSC-Reports-to-the-DC-Council/Renewable-Energy-Portfolio-Standard.aspx>.
218 "Renewable Energy Portfolio Standard Report with Data for Calendar Year 2021," Public Service Commission of Maryland (November 29, 2022) at 8, <https://www.psc.state.md.us/commission-reports/>.
219 *Id.*
220 "Renewable Portfolio Standard Report to the General Assembly for Compliance Year 2020," Public Utilities Commission of Ohio (November 2, 2021), <https://puco.ohio.gov/wps/portal/gov/puco/utilities/electricity/resources/ohio-renewable-energy-portfolio-standard/puco-annual-rps-reports>.
221 "Retail Electricity Supplier's RPS Compliance Report, Compliance Period: June 1, 2020–May 31, 2021," Delmarva Power, (Sept. 23, 2021), <https://depsc.delaware.gov/delawares-renewable-portfolio-standard-green-power-products/>
222 "Annual Report Fiscal Year 2018," Illinois Power Agency (Feb. 15, 2019) at 46, <https://www2.illinois.gov/sites/ipa/Pages/IPA_Reports.aspx>.
223 "Annual Report Regarding Renewable Energy and Energy Efficiency Portfolio Standard in North Carolina," North Carolina Utilities Commission (Oct. 1, 2019) at 38, <https://www.ncuc.net/Reps/reps.html>.
224 "Report on the Implementation and Cost-Effectiveness of the P.A. 295 Renewable Energy Standard," Michigan Public Service Commission (Feb. 18, 2020), <https://www.michigan.gov/mpsc/0,9535,7-395-93309_93438_93459_94932---,00.html>.
225 See RPS Report Summary 2005-2021, New Jersey's Clean Energy Program (May 17, 2022), <http://www.njcleanenergy.com/renewable-energy/program-updates/rps-compliance-reports>.
226 "New Jersey Board of Public Utilities Approves Solar Transition Program, Initiates a Cost Cap Proceeding," New Jersey Board of Public Utilities Press Release (December 6, 2019) <https://www.bpu.state.nj.us/bpu/newsroom/2019/approved/20191206.html>.
227 RPS compliance cost totals for Illinois, Michigan, and North Carolina reflect the RPS compliance cost attributable to PJM load in each of the states.
228 The actual PJM RPS compliance cost exceeds the reported $7.2 billion due to incomplete data. The compliance cost value for 2020 does not include Illinois, Michigan or North Carolina. Based on past data these states generally account for 3.0 percent of the total RPS compliance cost of PJM states

based on the reported compliance cost for the seven year period from 2014 through 2020 was $1.0 billion. The compliance cost for 2020, the most recent year with almost complete data, was $1.5 billion.

Table 8-27 RPS Compliance Cost[229] [230] [231] [232] [233] [234] [235] [236] [237] [238] [239]

Jurisdiction with RPS		2014	2015	2016	2017	2018	2019	2020	2021
Delaware	Total RPS		$16,013,421	$18,409,631	$18,772,855	$18,341,916	$19,401,476	$21,133,971	
	Solar		$7,070,254	$7,748,073	$7,105,726	$6,565,240	$8,121,914	$9,096,298	
	Non-Solar		$8,943,167	$10,661,557	$11,667,129	$11,776,676	$11,279,562	$12,037,673	
Illinois	Total RPS	$21,701,688	$24,817,068	$25,718,863	$25,919,372	$25,775,523			
Maryland	Total RPS	$104,056,879	$126,752,147	$135,232,457	$72,064,102	$84,874,724	$142,275,744	$223,218,944	$409,846,140
	Solar	$29,388,337	$39,062,714	$45,556,987	$21,276,834	$27,352,183	$57,824,616	$122,973,787	$221,296,225
	Tier I	$70,677,220	$85,070,001	$88,234,024	$50,099,228	$56,473,113	$84,333,097	$99,836,397	$187,579,231
	Tier II	$3,991,322	$2,619,432	$1,441,446	$688,040	$1,049,428	$118,031	$408,760	$970,684
Michigan	Total RPS	$476,535	$0	$3,264,504	$3,961,262	$3,264,504			
New Jersey	Total RPS	$395,782,297	$524,761,382	$593,441,037	$606,312,461	$653,810,457	$763,108,366	$960,423,760	
	Solar	$322,504,920	$417,359,783	$481,540,738	$503,797,182	$560,509,712	$667,975,153	$812,493,029	
	Class I	$66,071,749	$98,185,431	$100,910,465	$91,872,615	$83,474,335	$85,522,028	$130,272,633	
	Class II	$7,205,628	$9,216,167	$10,989,834	$10,642,664	$9,826,410	$9,611,185	$17,658,099	
North Carolina	Total RPS	$297,513	$358,436	$317,644	$234,264	$442,579			
Ohio	Total RPS	$42,581,477	$42,584,233	$37,631,481	$39,943,836	$50,214,523	$69,812,721	$81,752,397	
	Solar	$17,666,730	$14,843,052	$11,564,584	$9,435,730	$9,419,092	$9,578,048	$0	
	Non-Solar	$24,914,747	$27,741,181	$26,066,897	$30,508,106	$40,795,431	$60,234,672	$81,752,397	
Pennsylvania	Total RPS	$86,184,477	$114,586,932	$125,041,911	$115,585,212	$99,681,713	$112,691,066	$182,995,718	$307,751,404
	Solar	$14,163,543	$19,227,690	$21,876,876	$17,987,722	$16,565,924	$20,608,103	$24,764,538	$27,673,083
	Tier I	$70,922,431	$94,339,032	$101,700,328	$95,370,456	$77,899,586	$74,780,310	$100,528,434	$159,457,100
	Tier II	$1,098,503	$1,020,210	$1,464,707	$2,227,034	$5,216,203	$17,302,653	$57,702,746	$120,621,222
Washington D.C.	Total RPS	$27,372,970	$38,540,633	$47,163,353	$42,678,813	$50,609,701	$57,300,000	$65,000,000	
	Solar	$25,145,143	$36,526,662	$44,897,161	$38,571,061	$45,673,261	$51,982,914	$59,897,169	
	Tier I	$2,140,860	$1,899,232	$2,132,072	$3,960,018	$4,809,857	$5,262,354	$5,102,831	
	Tier II	$86,966	$114,738	$134,119	$147,734	$126,583	$54,733	$0	
PJM	Total RPS	$678,453,836	$888,414,253	$986,220,882	$925,472,176	$987,015,639	$1,164,589,372	$1,534,524,790	$717,597,544

229 Several states have not released compliance reports for 2020.
230 "Retail Electricity Supplier's RPS Compliance Report," Delmarva Power (Sept. 23, 2021), <https://depsc.delaware.gov/delawares-renewable-portfolio-standard-green-power-products/>.
231 "Fiscal Year 2018 Annual Report," February 15, 2019, "Report on Costs and Benefits of Renewable Resource Procurement," April 1, 2016, Illinois Power Agency (IPA), <https://www2.illinois.gov/sites/ipa/Pages/IPA_Reports.aspx>. The compliance cost entry for Illinois represents the ComEd cost of RECs as given in Section 11, Table 2.
232 "Renewable Energy Portfolio Standard Report," Public Service Commission of Maryland (Nov. 2021) at 8, <https://www.psc.state.md.us/commission-reports/>.
233 Appendix C in "Report on the Implementation and Cost-Effectiveness of the P.A. 295 Renewable Energy Standard," Michigan Public Service Commission, February 18, 2020, <https://www.michigan.gov/mpsc/0,9535,7-395-93309_93438_93459_94932---,00.html>. The compliance cost entry reflects the compliance cost of the Indiana Michigan Power Company, which is the only investor owned utilities whose service area is in the PJM footprint.
234 "RPS Report Summary 2005-2020," New Jersey's Clean Energy Program, April 13, 2021, <http://njcleanenergy.com/renewable-energy/program-updates/rps-compliance-reports>.
235 "Renewable Portfolio Standard Report to the General Assembly for Compliance Year 2020," Public Utilities Commission of Ohio, Nov. 2, 2021, <https://puco.ohio.gov/wps/portal/gov/puco/utilities/electricity/resources/ohio-renewable-energy-portfolio-standard/puco-annual-rps-reports>.
236 "2020 Annual Report Alternative Energy Portfolio Standards Act of 2004," Pennsylvania Public Utility Commission, February 2021 <https://www.puc.pa.gov/media/1410/aeps-annreport2020.pdf>.
237 "Report on the Renewable Energy Portfolio Standard for Compliance Year 2020," Public Service Commission of the District of Columbia, Executive Summary, May 3, 2021, <https://dcpsc.org/Orders-and-Regulations/PSC-Reports-to-the-DC-Council/Renewable-Energy-Portfolio-Standard.aspx>.
238 "Application of Dominion Energy North Carolina for Approval of Cost Recovery for Renewable Energy and Energy Efficiency Portfolio Standard Compliance and Related Costs," Docket No. E-22, Sub 557, Sub 558, August 30, 2018 <https://www.ncuc.net/>. The North Carolina compliance cost entries reflects the compliance cost of Dominion Energy North Carolina.
239 The reporting period for RPS compliance in Delaware, Illinois, New Jersey, and Pennsylvania corresponds to PJM capacity market delivery years, June 1 through May 31. The compliance cost amounts reported by these states were converted to calendar year by assuming the compliance cost was evenly spread across the months in the compliance year.

Emission Controlled Capacity and Emissions

Emission Controlled Capacity

Environmental regulations affect decisions about emission control investments in existing units, investment in new units and decisions to retire units lacking emission controls.[240] Most PJM units burning fossil fuels have installed emission control technology. All coal steam units in PJM are compliant with the state and federal emissions limits established by MATS.[241] [242]

Table 8-28 shows SO_2 emission controls by fossil fuel fired units in PJM.[243] [244] [245] Coal has the highest SO_2 emission rate, while natural gas and diesel oil have lower SO_2 emission rates.[246] Of the current 51,733.2 MW of coal capacity in PJM, 49,671.0 MW of capacity, 96.0 percent, has some form of FGD (flue-gas desulfurization) technology to reduce SO_2 emissions.

Table 8-28 SO_2 emission controls by fuel type (MW): March 31, 2023[247]

	SO_2 Controlled	No SO_2 Controls	Total	Percent Controlled
Coal	49,671.0	2,062.2	51,733.2	96.0%
Diesel Oil	0.0	4,606.4	4,606.4	0.0%
Natural Gas	0.0	67,784.6	67,784.6	0.0%
Other	325.0	3,500.0	3,825.0	8.5%
Total	49,996.0	77,953.2	127,949.2	39.1%

Table 8-29 shows NO_X emission controls by fossil fuel fired units in PJM. Coal has the highest NO_X emission rate, while natural gas and diesel oil have lower NO_X emission rates. Of the current 51,733.2 MW of coal capacity in PJM, 51,604.2 MW of capacity, 99.8 percent, has some form of emissions controls to reduce NO_X emissions. Most units in PJM have NO_X emission controls in order to meet each state's emission compliance standards, based on whether a state is part of CSAPR, Acid Rain Program (ARP) or a combination of the three. The NO_X compliance standards of MATS require the use of selective catalytic reduction (SCRs) or selective non-catalytic reduction (SCNRs) for coal steam units, as well as SCRs or water injection technology for peaking combustion turbine units.[248]

Table 8-29 NO_X emission controls by fuel type (MW): As of March 31, 2023

	NO_x Controlled	No NO_x Controls	Total	Percent Controlled
Coal	51,604.2	129.0	51,733.2	99.8%
Diesel Oil	1,020.3	3,586.1	4,606.4	22.1%
Natural Gas	67,541.6	243.0	67,784.6	99.6%
Other	1,575.0	2,250.0	3,825.0	41.2%
Total	121,741.1	6,208.1	127,949.2	95.1%

Table 8-30 shows particulate emission controls by fossil fuel units in PJM. Almost all coal units (99.8 percent) in PJM have particulate controls, as well as a few natural gas units (4.3 percent) and units with other fuel sources (51.6 percent). Typically, technologies such as electrostatic precipitators (ESP) or fabric filters (baghouses) are used to reduce particulate matter from coal steam units.[249] Fabric filters work by allowing the flue gas to pass through a tightly woven fabric which filters out the particulates. Of the current 51,733.2 MW of coal capacity in PJM, 51,648.2 MW of capacity, 99.8 percent, have some type of particulate emissions control technology.

Table 8-30 Particulate emission controls by fuel type (MW): As of March 31, 2023

	Particulate Controlled	No Particulate Controls	Total	Percent Controlled
Coal	51,648.2	85.0	51,733.2	99.8%
Diesel Oil	0.0	4,606.4	4,606.4	0.0%
Natural Gas	2,912.0	64,872.6	67,784.6	4.3%
Other	1,972.0	1,853.0	3,825.0	51.6%
Total	56,532.2	71,417.0	127,949.2	44.2%

240 See EPA, "National Ambient Air Quality Standards (NAAQS)," <https://www.epa.gov/criteria-air-pollutants/naaqs-table> (Accessed March 4, 2022).
241 On April 16, 2020, the EPA issued a revised final finding regarding the Mercury and Air Toxics Standards. See EPA. "Regulatory Actions," <https://www.epa.gov/mats/regulatory-actions-final-mercury-and-air-toxics-standards-mats-power-plants> (Accessed May 7, 2020).
242 On April 9, 2020, the EPA created a new subcategory of six coal refuse power plants in Pennsylvania and West Virginia with reduced limits of HCl and SO_2 emissions under MATS. These units were all compliant with the previous MATS rules. "Mercury and Air Toxics Standards," <https://www.epa.gov/sites/production/files/2020-04/documents/frn_mats_coal_refuse_2060-au48_final_rule.pdf> (Accessed May 7, 2020)
243 See EPA, "Air Market Programs Data," <http://ampd.epa.gov/ampd/> (Accessed March 4, 2022).
244 Air Markets Programs Data is submitted quarterly. Generators have 60 days after the end of the quarter to submit data, and all data is considered preliminary and subject to change until it is finalized in June of the following year. The most recent complete set of emissions data is from 2021.
245 The total MW are less than the 183,311.8 reported in Section 5: Capacity Market, because EPA data on controls could not be matched to some PJM units. "Air Markets Program Data," <http://ampd.epa.gov/ampd/QueryToolie.html> (Accessed March 4, 2022).
246 Diesel oil includes number 1, number 2, and ultra-low sulfur diesel. See EPA, "Electronic Code of Federal Regulations, Title 40, Chapter 1, Subchapter C, Part 72, Subpart A, Section 72.2," <http://www.ecfr.gov/cgi-bin/text-idx?SID=4f18612541a393473efb13acb879d470&mc=true&node=se40.18.72_12&rgn=div8> (Accessed May 7, 2020).
247 The "other" category includes petroleum coke, wood, process gas, residual oil, other gas, and other oil. The EPA's "other" category does not have strict definitions for inclusion.
248 See EPA. "Mercury and Air Toxics Standards, Cleaner Power Plants," <https://www.epa.gov/mats/cleaner-power-plants#controls> (Accessed May 7, 2020).
249 See EPA, "Air Pollution Control Technology Fact Sheet," <https://www3.epa.gov/ttn/catc/dir1/ff-pulse.pdf> (Accessed May 4, 2022).

In order to achieve compliance with MATS, most coal steam units in PJM have particulate emission controls in the form of ESPs, but many units have also installed baghouse technology, or a combination of an FGD and SCR. Currently, all of the 108 coal steam units have some combination of ESP, baghouse, or FGD and SCR technology installed to achieve MATS compliance for either SO_2 or particulate emissions control, representing all of the 51,733.2 MW total coal capacity.

Emissions

Figure 8-10 shows the total CO_2 emissions in short tons, the CO_2 emission rate in short tons per MWh within PJM for all CO_2 emitting units, for each quarter from 1999 to the first quarter of 2023, and the CO_2 emission rate in short tons per MWh of total generation within PJM for each quarter from the third quarter of 2000 to the first quarter of 2023.[250]

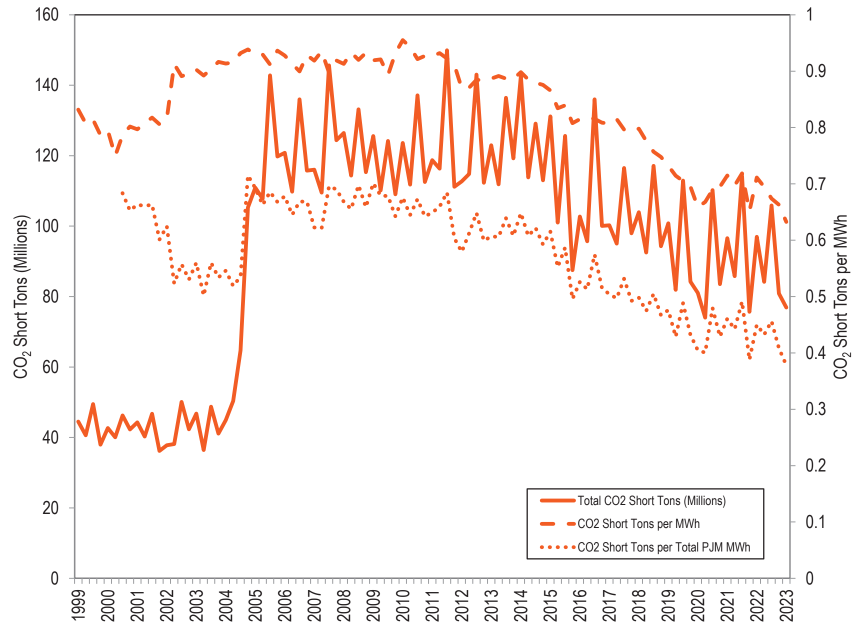
Figure 8-11 shows the total CO_2 emission in short tons on peak and off peak and the CO_2 emission rate in short tons per MWh for all CO_2 emitting units.

Table 8-31 shows the minimum and maximum CO_2 emission rates in short tons per MWh for all CO_2 emitting units, for all hours, as well as on and off peak hours, from the third quarter of 1999 through the third quarter of 2022.

Total PJM generation decreased from 215,415.1 GWh in the first quarter of 2022 to 203,326.4 GWh in the first quarter of 2023, while CO_2 produced decreased from 96,970.3 million short tons in the first quarter of 2022 to 76,894.7 million short tons in the first quarter of 2023.[251] The CO_2 emission rate averaged 0.70 short tons per MWh for all CO_2 emitting units in 2021, 0.69 short tons per MWh for all CO_2 emitting units in 2022, and 0.63 short tons per MWh for all CO_2 emitting units in the first three months of 2023.

250 Unless otherwise noted, emissions are measured in short tons. A short ton is 2,000 pounds.
251 See the *2021 Annual State of the Market Report for PJM*: Section 3: Energy Market, Table 3-10.

Figure 8-10 CO_2 emissions by quarter (millions of short tons), by PJM units: January 1999 through March 2023[252 253]



In the first quarter of 2023, CO_2 emission rates were 0.63 short tons per MWh for all CO_2 emitting units for off peak hours, and 0.63 for on peak hours. Of the top 10 largest CO_2 emitting units in the United States, three (Gavin, Prairie State, and Amos) are located in the PJM footprint.[254]

252 The emissions are calculated from the continuous emission monitoring system (CEMS) data from generators located within the PJM footprint.
253 In 2004 and 2005, PJM integrated the American Electric Power (AEP), ComEd, Dayton Power & Light Company (DAY), Dominion, and Duquesne Light Company (DLCO) Control Zones. The large increase in total emissions from 2004 to 2005 was a result of these integrations. In June 2011, PJM integrated the American Transmission Systems, Inc. (ATSI) Control Zone. In January 2012, PJM integrated the Duke Energy Ohio/Kentucky (DEOK) Control Zone. In June 2013, PJM integrated the Eastern Kentucky Power Cooperative (EKPC). In December 2018, PJM integrated the Ohio Valley Electric Corporation (OVEC).
254 "The top 10 emitting power plants in America," <https://www.eenews.net/articles/the-top-10-emitting-power-plants-in-america/> (Accessed November 4, 2022).

Figure 8-11 Total CO_2 emissions during on and off peak hours by quarter (millions of short tons), by PJM units: January 1999 through March 2023[255]

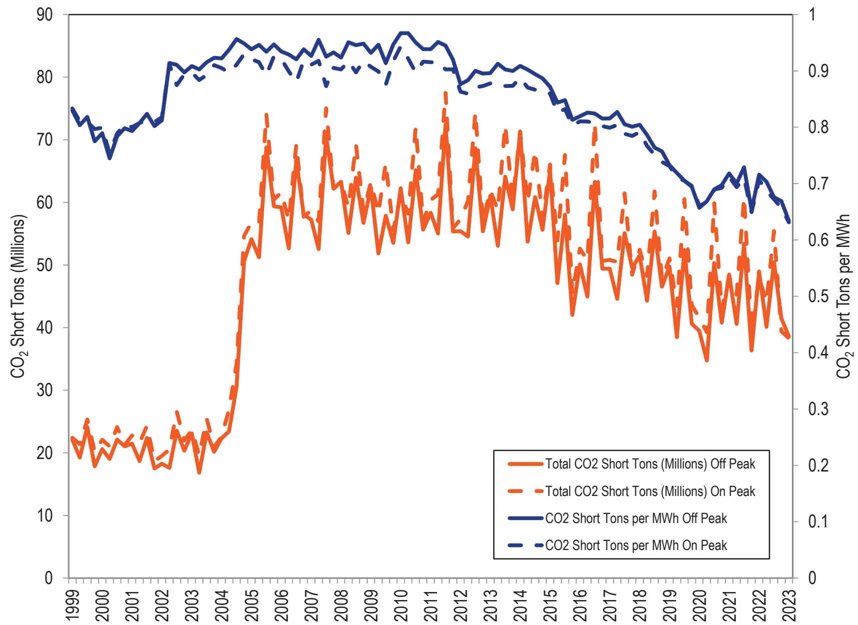


Table 8-31 Minimum and maximum CO_2 emissions per MWh: September 1999 through March 2023

		Short Tons per MWh	Year	Quarter
Minimum	All hours	0.63	2023	1
	On Peak	0.63	2023	1
	Off Peak	0.63	2023	1
Maximum	All hours	0.96	2010	1
	On Peak	0.94	2010	1
	Off Peak	0.97	2010	2

Figure 8-12 shows the total SO_2 and NO_X emissions and the emission rate in short tons per MWh for all SO_2 and NO_X emitting units, and the SO_2 and NO_X emission rate in short tons per MWh of total PJM generation. In the first quarter of 2023, the SO_2 emission rate was 0.000283 short tons per MWh for all SO_2 emitting units, and the NO_x emission rate was 0.000228 short tons per MWh for all NO_X emitting units.

Figure 8-13 shows the total on peak hour and off peak hour SO_2 and NO_X emissions and the emission rate in short tons per MWh for all SO_2 and NO_X emitting units. In the first quarter of 2023, SO_2 emission rates were 0.000280 short tons per MWh and 0.000286 short tons per MWh for all SO_2 units, for off and on peak hours. In the first quarter of 2023, NO_X emission rates were 0.000227 short tons per MWh and 0.000229 short tons per MWh for all NO_X emitting units, for off and on peak hours.

Table 8-32 shows the minimum and maximum SO_2 and NO_x emission rate in short tons per MWh for all SO_2 and NO_X emitting units, for all hours, as well as on and off peak hours, from the third quarter of 1999 through the first quarter of 2023.

The consistent decline in SO_2 and NO_X emissions starting in 2006 is the result of a decline in the use of coal, an increase in the use of natural gas, and the installation of environmental controls from 2006 to 2023.[256 257]

255 The emissions are calculated from the continuous emission monitoring system (CEMS) data from generators located within the PJM footprint.

256 See EIA, "Changes in coal sector led to less SO_2 and NO_x emissions from electric power industry," <https://www.eia.gov/todayinenergy/detail.php?id=37752> (Accessed October 25, 2019).

257 See EIA, "Sulfur dioxide emissions from U.S. power plants have fallen faster than coal generation," <https://www.eia.gov/todayinenergy/detail.php?id=29812> (Accessed October 25, 2019).

Figure 8-12 SO_2 and NO_x emissions by quarter (thousands of short tons), by PJM units: January 1999 through March 2023[258]

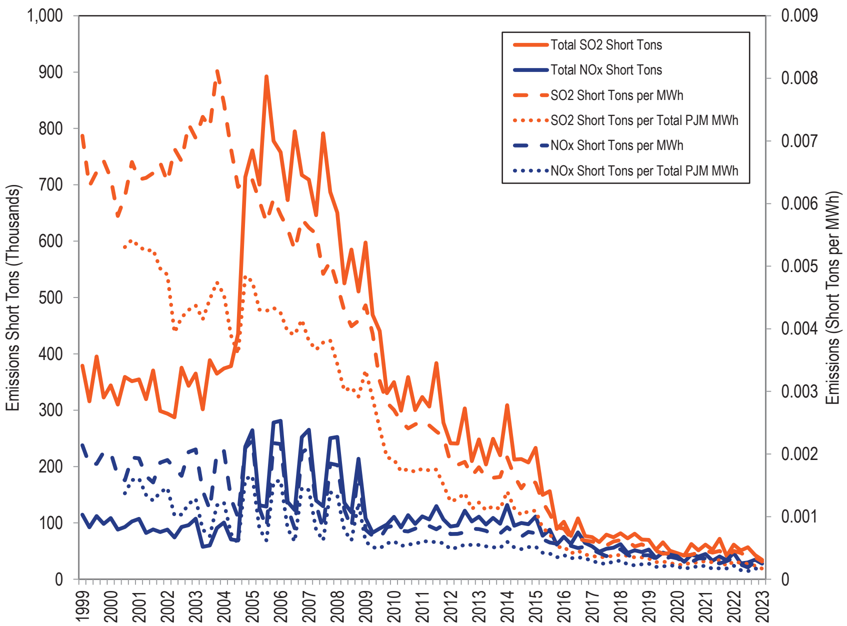


Figure 8-13 SO_2 and NO_x emissions during on and off peak hours by quarter (thousands of short tons), by PJM units: January 1999 through March 2023[259]

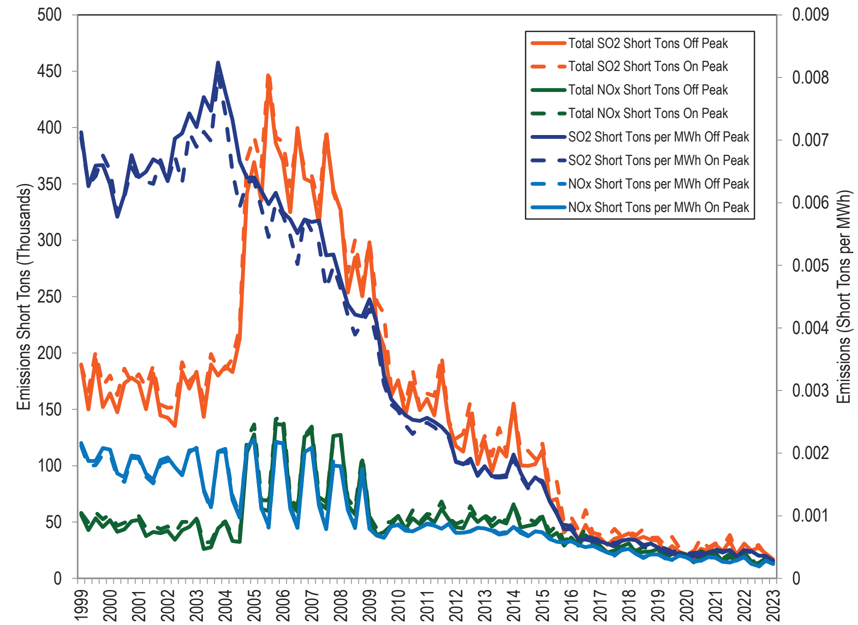


Table 8-32 Minimum and maximum SO_2 and NO_x emissions per MWh: September 1999 through March 2023

Emission Type			Short Tons per MWh	Year	Quarter
SO_2	Minimum	All hours	0.000	2023	1
		On Peak	0.000	2023	1
		Off Peak	0.000	2023	1
	Maximum	All hours	0.008	2003	4
		On Peak	0.008	2003	4
		Off Peak	0.008	2003	4
NO_x	Minimum	All hours	0.000	2022	3
		On Peak	0.000	2022	3
		Off Peak	0.000	2022	3
	Maximum	All hours	0.002	2005	1
		On Peak	0.002	2005	1
		Off Peak	0.002	2005	1

258 The emissions are calculated from the continuous emission monitoring system (CEMS) data from generators located within the PJM footprint.

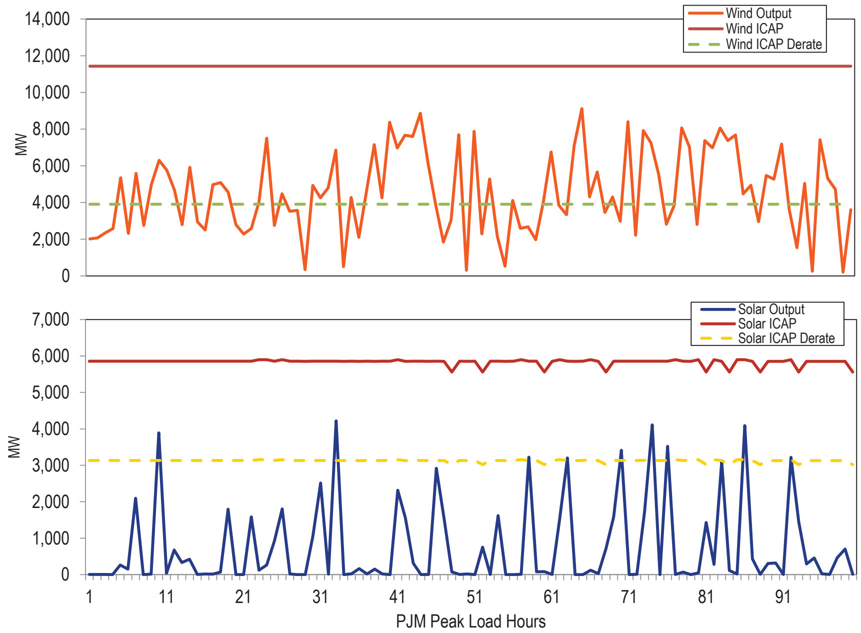
259 The emissions are calculated from the continuous emission monitoring system (CEMS) data from generators located within the PJM footprint.

Renewable Energy Output

Wind and Solar Peak Hour Output

The capacity of solar and wind resources are derated from the nameplate or installed capacity value to a level intended to reflect that the resources are a substitute for other capacity resources in the PJM Capacity Market. The derating percentages are intended to reflect expected performance during high load hours and are based on actual historical performance. Figure 8-14 shows the wind and solar output during the top 100 load hours in PJM in the first three months of 2023. In the first three months of 2023, 77 of the top 100 load hours in PJM are PJM defined peak load hours. The hours are in descending order by load. The solid lines are the total ICAP of wind or solar PJM resources. The dashed lines are the total capacity committed for each unit, or the ICAP of wind and solar PJM resources derated to 14.7 and 38.0 percent if the unit does not participate in the capacity market. The actual output of the wind and solar resources during the top 100 load hours ranges above and below the derated capacity values. Wind output was above the derated ICAP for 58 hours and below the derated ICAP for 42 hours of the top 100 load hours in the first three months of 2023. The wind capacity factor for the top 100 load hours in the first three months of 2023 was 39.8 percent. Wind output was above the derated ICAP for 1,232 hours and below the derated ICAP for 927 hours in the first three months of 2023. The wind capacity factor in the first three months of 2022 was 40.2 percent. Solar output was above the derated ICAP for 9 hours and below the derated ICAP for 91 hours of the top 100 load hours in the first three months of 2023. The solar capacity factor for the top 100 load hours in the first three months of 2023 was 12.7 percent. Solar output was above the derated ICAP for 242 hours and below the derated ICAP for 1,917 hours in the first three months of 2023. The solar capacity factor in the first three months of 2023 was 15.5 percent.

Figure 8-14 Wind and solar output during the top 100 load hours: January through March, 2023



Wind Units

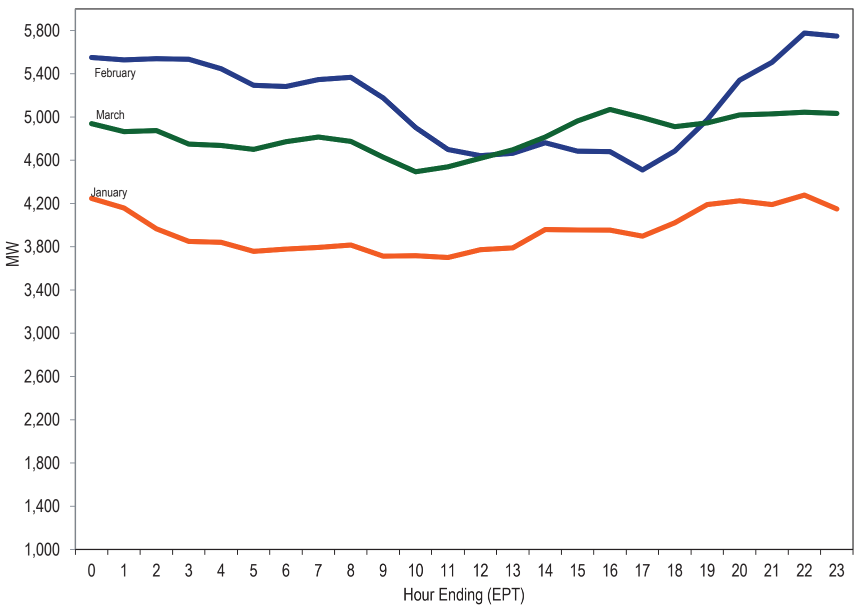
Table 8-33 shows the capacity factors of wind units in PJM. In the first three months of 2023, the capacity factor of wind units in PJM was 40.2 percent. Wind units that were capacity resources had a capacity factor of 40.4 percent and an installed capacity of 9,988.9 MW. Wind units that were energy only had a capacity factor of 39.1 percent and an installed capacity of 1,442.7 MW. Wind capacity in RPM is derated to 14.7 or 17.6 percent of nameplate capacity for the capacity market, based on the wind farm terrain, and energy only resources are not included in the capacity market.

Table 8-33 Capacity factor of wind units: January through March, 2023[260]

Type of Resource	Capacity Factor	Installed Capacity (MW)
Energy-Only Resource	39.1%	1,442.7
Capacity Resource	40.4%	9,988.9
All Units	40.2%	11,431.6

Figure 8-15 shows the average hourly real-time generation of wind units in PJM, by month for the first three months of 2023. The hour with the highest average output in the first three months of 2023, 5,776.6 MWh, occurred in February, and the hour with the lowest average output, 3,700.6 MWh, occurred in January. Wind output in PJM is generally higher during off peak hours and lower during on peak hours.

Figure 8-15 Average hourly real-time generation of wind units: January through March, 2023



260 Capacity factor is calculated based on online date of the resource.

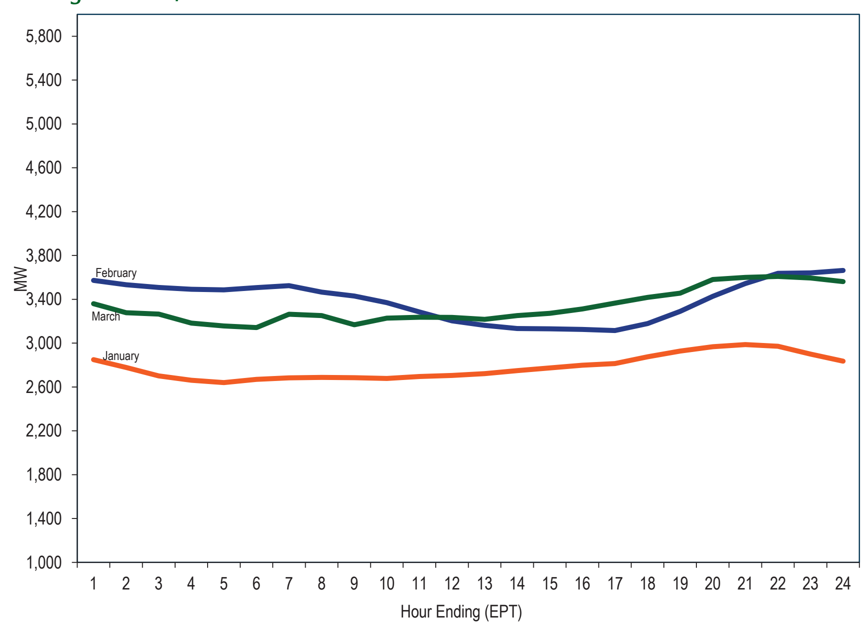
Table 8-34 shows the generation and capacity factor of wind units by month for the first three months of 2022 and 2023.

Table 8-34 Capacity factor of wind units in PJM by month: January through March, 2022 and 2023

	2022		2023	
Month	Generation (MWh)	Capacity Factor	Generation (MWh)	Capacity Factor
January	3,072,620.3	36.4%	2,913,720.6	34.3%
February	3,256,337.2	42.8%	3,440,914.0	44.8%
March	3,386,619.2	40.2%	3,574,026.7	42.1%

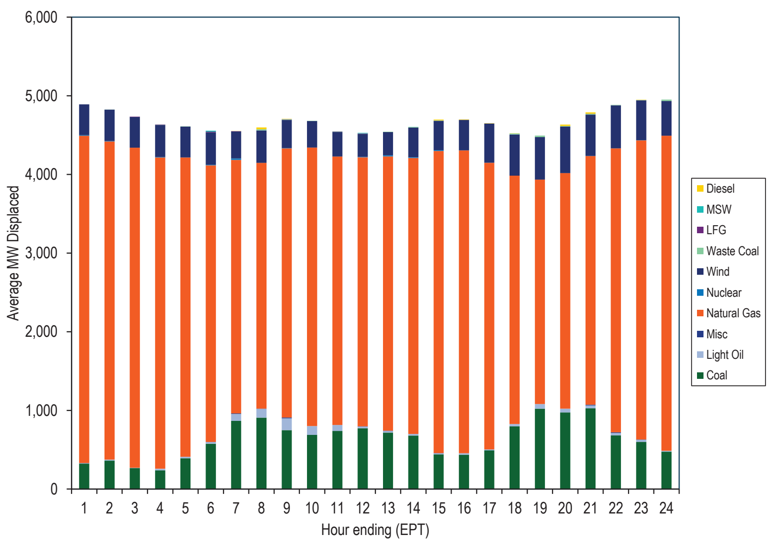
Wind units that are capacity resources are required, like all capacity resources except demand resources, to offer the energy associated with their cleared capacity in the day-ahead energy market and in the real-time energy market. Figure 8-16 shows the average hourly day-ahead generation offers of wind units in PJM, by month.

Figure 8-16 Average hourly day-ahead generation of wind units: January through March, 2023



Output from wind turbines displaces output from other generation types because, in general, wind turbines generate power when the wind is blowing, regardless of the price. This displacement affects the output of marginal units in PJM. The magnitude and type of effect on marginal unit output depends on the level of wind turbine output, its location, time and duration. One measure of this displacement is based on the mix of marginal units when wind is producing output.[261] Figure 8-17 and Table 8-35 show the hourly average proportion of marginal units by fuel type mapped to the hourly average MW of real-time wind generation in the first three months of 2023. This is not an exact measure of displacement because it is not based on a redispatch of the system without wind resources. In the first three months of 2023, the SCED dispatch instruction for marginal wind resources was to reduce output for 65.0 percent of the wind unit intervals. When wind appears as the displaced fuel at times when wind resources were on the margin this means that there was no displacement for those hours, if the dispatch instruction was to lower the generation. The level of wind displaced by wind is thus overstated.

Figure 8-17 Marginal fuel at time of wind generation: January through March, 2023



261 The measure is based on the principle that any incremental change in the wind output is balanced by the change in the output of marginal generators, while holding everything else equal.

Table 8-35 Marginal fuel MW at time of wind generation: January through March, 2023

Hour	Coal	Light Oil	Misc	Natural Gas	Nuclear	Wind	Waste Coal	LFG	MSW	Diesel	Total
0	324.1	4.9	1.3	4,161.9	8.7	390.6	0.0	0.0	0.0	0.0	4,891.5
1	362.1	11.4	0.0	4,047.0	5.2	397.9	1.0	0.0	0.0	0.0	4,824.5
2	267.4	2.7	0.0	4,070.0	0.0	390.7	0.0	5.9	0.0	0.0	4,736.6
3	237.2	21.8	0.0	3,956.4	5.4	409.6	1.6	2.9	0.0	0.0	4,634.9
4	391.2	17.5	2.0	3,805.2	0.0	392.0	4.0	0.0	0.0	0.0	4,612.0
5	576.9	19.8	1.8	3,516.7	8.0	413.0	0.0	7.3	12.9	0.0	4,556.5
6	866.1	88.0	7.5	3,222.9	20.1	342.6	0.0	3.3	0.0	1.6	4,552.1
7	908.3	110.2	2.5	3,127.3	0.9	409.9	16.0	0.0	0.0	22.1	4,597.1
8	748.4	150.9	10.0	3,422.5	2.6	360.0	7.0	1.9	0.0	3.1	4,706.5
9	687.8	113.6	0.0	3,541.0	0.0	335.7	4.3	0.0	0.0	0.0	4,682.4
10	738.9	75.1	0.0	3,414.2	0.0	313.8	3.0	2.1	0.0	0.0	4,547.1
11	773.0	21.6	2.5	3,421.1	4.1	293.6	1.1	5.4	5.4	0.0	4,527.9
12	718.1	19.3	4.8	3,487.7	13.7	296.1	4.7	0.0	0.0	0.0	4,544.4
13	680.0	19.9	0.0	3,508.5	9.1	377.6	7.9	0.0	2.3	0.0	4,605.3
14	439.9	13.7	3.1	3,842.8	9.4	373.5	5.2	0.0	0.0	10.0	4,697.7
15	436.0	19.2	0.0	3,850.6	0.0	389.0	0.0	0.0	0.0	4.1	4,699.0
16	492.2	11.5	0.0	3,644.2	2.5	497.6	0.0	0.0	0.0	3.3	4,651.4
17	796.4	30.8	0.0	3,157.0	0.0	523.3	9.1	0.0	2.4	3.4	4,522.5
18	1,021.0	60.1	0.0	2,853.9	0.0	540.6	17.7	0.0	0.0	0.0	4,493.3
19	974.1	47.1	0.0	2,996.2	0.0	590.1	8.9	0.0	0.0	17.4	4,633.7
20	1,026.3	37.1	9.0	3,160.3	2.1	525.5	9.3	2.4	0.0	16.5	4,788.6
21	682.0	31.3	7.1	3,611.1	0.0	547.8	5.2	0.0	0.0	0.0	4,884.6
22	598.4	27.2	4.2	3,804.3	1.4	507.0	4.1	0.0	0.0	3.2	4,949.9
23	475.1	12.0	0.0	4,004.3	0.0	443.4	17.3	0.0	0.0	0.0	4,952.1
Average	634.2	40.3	2.3	3,567.8	3.9	419.2	5.3	1.3	1.0	3.5	4,678.8

Solar Units

Solar units in PJM may be in front of or behind the meter. The data reported include all and only PJM solar units that are in front of the meter. As shown in Table 8-22, there are 6,985.3 MW of solar capacity registered in GATS that are PJM units. As shown in Table 8-23, there are 9,698.3 MW capacity of solar registered in GATS that are not PJM units. Some behind the meter generation exists in clusters, such as community solar farms. The customers of these clusters may or may not be located at the same node on the transmission system as the solar farm. When behind the meter generation and its associated load are at separate nodes, loads should pay for the appropriate level of transmission service, and should not be permitted to avoid paying appropriate costs as a result of badly designed rules, such as rules for netting. The MMU recommends that load and generation located at separate nodes be treated as separate resources.

Table 8-36 shows the capacity factor of solar units in PJM. The capacity factor of solar units in PJM was 15.5 percent for the first three months of 2023. Solar units that were capacity resources had a capacity factor of 15.6 percent and an installed capacity of 3,703.7 MW. Solar units that were energy only had a capacity factor of 15.4 percent and an installed capacity of 2,109.5 MW. Solar capacity in RPM is derated to 38.0, 42.0 or 60.0 percent of nameplate capacity for the capacity market, based on the installation type, and energy only resources are not included in the capacity market.

Table 8-36 Capacity factor of solar units: January through March, 2023

Type of Resource	Capacity Factor	Installed Capacity (MW)
Energy-Only Resource	15.4%	2,109.5
Capacity Resource	15.6%	3,703.7
All Units	15.5%	5,813.2

Figure 8-18 shows the average hourly real-time generation of solar units in PJM, by month. The hour with the highest peak average output in the first three months of 2023, 3,474.4 MW, occurred in March, and the hour with the lowest peak average output, 1,954.3 MW, occurred in January. Solar output in PJM is generally higher during peak hours and lower during off peak hours.

Figure 8-18 Average hourly real-time generation of solar units: January through March, 2023

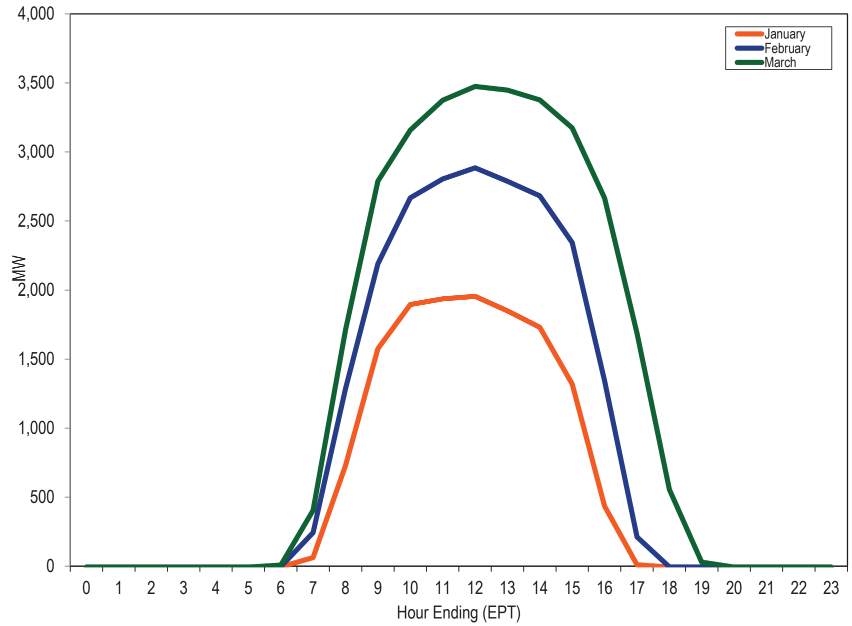


Table 8-37 shows the generation and capacity factor of solar units by month for the first three months of 2022 and 2023.

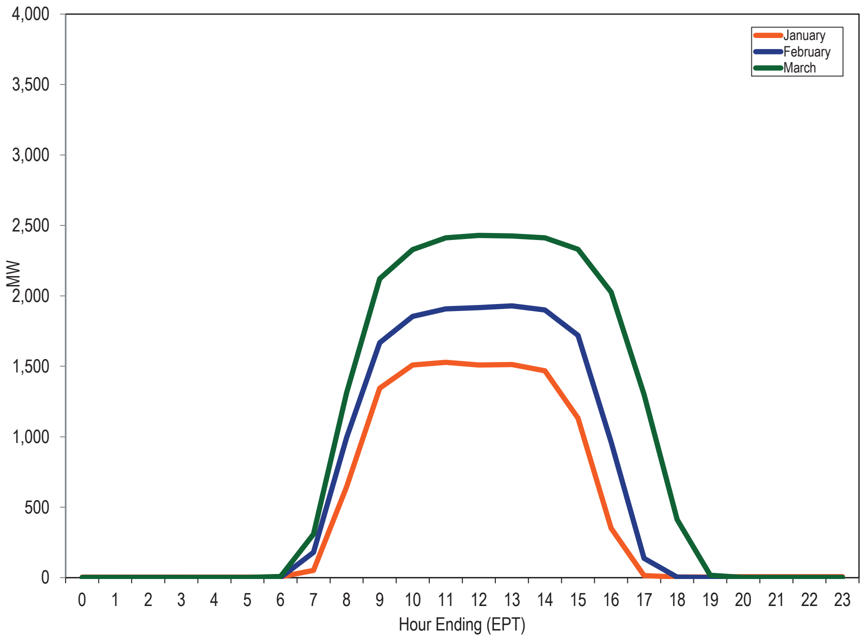
Table 8-37 Capacity factor of solar units by month: January through March, 2022 and 2023

	2022		2023	
Month	Generation (MWh)	Capacity Factor	Generation (MWh)	Capacity Factor
January	426,957.6	11.7%	417,821.3	9.9%
February	564,995.2	17.2%	598,407.5	15.2%
March	754,200.7	20.7%	928,052.2	21.2%

Solar units that are capacity resources are required, like all capacity resources except demand resources, to offer the energy associated with their cleared capacity in the day-ahead energy market and in the real-time energy market.

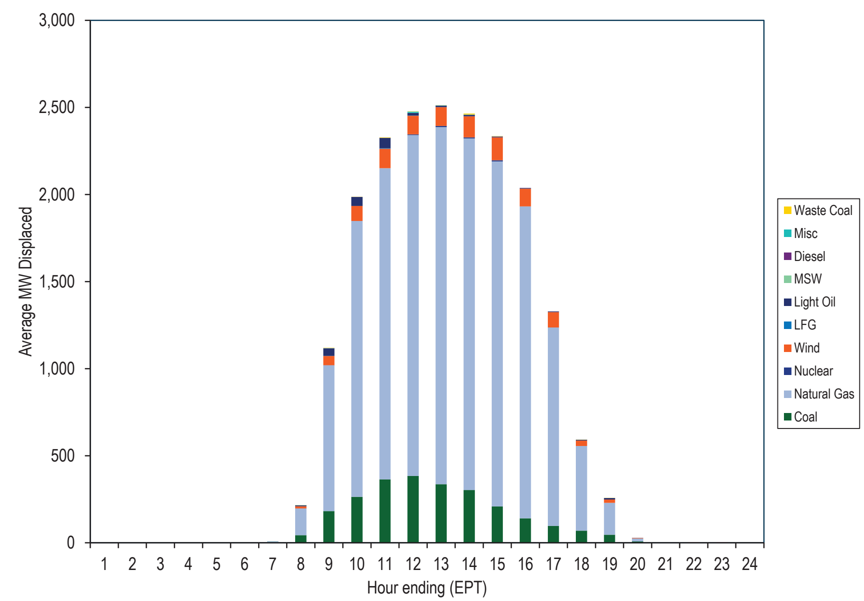
Figure 8-19 shows the average hourly day-ahead generation offers of solar units in PJM, by month.[262]

Figure 8-19 Average hourly day-ahead generation of solar units: January through March, 2023



Output from solar generators displaces output from other generation types because, in general, solar photovoltaic cells generate power when the sun is shining, regardless of the price. This displacement affects the output of marginal units in PJM. The magnitude and type of effect on marginal unit output depends on the level of solar generation output, its location, time and duration. One measure of this displacement is based on the mix of marginal units when a solar unit is producing output.[263] Figure 8-20 and Table 8-38 show the hourly average proportion of marginal units by fuel type mapped to the hourly average MW of real-time solar generation in the first three months of 2023. This is not an exact measure of displacement because it is not based on a redispatch of the system without solar resources. In the first three months of 2023, there were no marginal solar units. When solar appears as the displaced fuel at times when solar resources were on the margin this means that there was no displacement for those hours, if the dispatch instruction was to lower the generation. The level of solar displaced by solar is thus overstated.

Figure 8-20 Marginal fuel at time of solar generation: January through March, 2023



262 The average day-ahead generation of solar units in PJM is greater than 0 for hours when the sun is down due to some solar units being paired with landfill units.

263 The measure is based on the principle that any incremental change in the solar output is balanced by the change in the output of marginal generators, while holding everything else equal.

Table 8-38 Marginal fuel MW at time of solar generation: January through March, 2023

Hour	Coal	Natural Gas	Nuclear	Wind	LFG	Light Oil	MSW	Diesel	Misc	Waste Coal	Total
0	0.2	0.5	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.8
1	0.1	0.7	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.9
2	0.2	0.5	0.0	0.2	0.0	0.0	0.0	0.0	0.0	0.0	0.8
3	0.0	0.6	0.0	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.8
4	0.1	0.4	0.0	0.2	0.0	0.0	0.0	0.0	0.0	0.0	0.7
5	0.0	0.2	0.0	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.3
6	1.2	3.7	0.0	0.2	0.0	0.0	0.0	0.0	0.0	0.0	5.2
7	43.9	153.6	0.1	12.2	0.0	5.0	0.0	0.7	0.1	0.8	216.2
8	181.8	837.2	0.4	52.7	0.8	43.6	0.0	1.0	0.7	1.3	1,119.5
9	264.3	1,583.4	0.0	86.6	0.0	51.8	0.0	0.0	0.0	0.7	1,986.8
10	364.3	1,786.9	0.0	111.7	2.3	60.6	0.0	0.0	0.0	2.7	2,328.4
11	383.8	1,957.3	4.0	107.2	1.2	14.3	1.2	0.0	7.2	1.9	2,478.0
12	336.1	2,051.0	7.0	107.4	0.0	9.3	0.0	0.0	1.2	1.1	2,513.0
13	302.8	2,019.1	6.5	120.5	0.0	9.2	1.6	0.0	0.0	5.0	2,464.7
14	208.4	1,981.8	6.8	131.1	0.0	3.3	0.0	2.2	0.9	1.3	2,335.7
15	140.5	1,790.9	0.0	102.4	0.0	3.2	0.0	0.6	0.0	0.0	2,037.6
16	96.8	1,139.5	0.2	87.7	0.0	3.4	0.0	0.2	0.0	0.0	1,327.8
17	69.8	486.1	0.0	31.3	0.0	3.6	0.0	0.0	0.0	0.0	590.9
18	46.4	182.7	0.0	19.0	0.0	8.8	0.0	0.0	0.0	0.1	257.0
19	7.0	17.4	0.0	2.5	0.0	0.4	0.0	0.0	0.0	0.0	27.4
20	0.1	0.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.8
21	0.1	1.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.2
22	0.1	1.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.2
23	0.2	0.6	0.0	0.3	0.0	0.0	0.0	0.0	0.0	0.0	1.1
Average	102.0	666.5	1.0	40.6	0.2	9.0	0.1	0.2	0.4	0.6	820.7

Interchange Transactions

PJM market participants import energy from, and export energy to, external regions continuously. The transactions involved may fulfill long-term or short-term bilateral contracts or respond to price differentials. The external regions include both market and nonmarket balancing authorities.

Overview

Interchange Transaction Activity

- **Aggregate Imports and Exports in the Real-Time Energy Market.** In the first three months of 2023, PJM was a monthly net exporter of energy in the real-time energy market in all months.[1] In the first three months of 2023, the real-time net interchange was -8,339.9 GWh. The real-time net interchange in the first three months of 2022 was -9,458.6 GWh.
- **Aggregate Imports and Exports in the Day-Ahead Energy Market.** In the first three months of 2023, PJM was a monthly net exporter of energy in the day-ahead energy market in all months. In the first three months of 2023, the total day-ahead net interchange was -8,385.4 GWh. The day-ahead net interchange in the first three months of 2022 was -8,737.1 GWh.
- **Aggregate Imports and Exports in the Day-Ahead and the Real-Time Energy Market.** In the first three months of 2023, gross imports in the day-ahead energy market were 111.7 percent of gross imports in the real-time energy market (83.7 percent in the first three months of 2022). In the first three months of 2023, gross exports in the day-ahead energy market were 104.4 percent of the gross exports in the real-time energy market (89.6 percent in the first three months of 2022).
- **Interface Imports and Exports in the Real-Time Energy Market.** In the first three months of 2023, there were net scheduled exports at 14 of PJM's 19 interfaces in the real-time energy market.
- **Interface Pricing Point Imports and Exports in the Real-Time Energy Market.** In the first three months of 2023, there were net scheduled exports at five of PJM's seven interface pricing points eligible for real-time transactions in the real-time energy market.
- **Interface Imports and Exports in the Day-Ahead Energy Market.** In the first three months of 2023, there were net scheduled exports at 12 of PJM's 19 interfaces in the day-ahead energy market.
- **Interface Pricing Point Imports and Exports in the Day-Ahead Energy Market.** In the first three months of 2023, there were net scheduled exports at six of PJM's seven interface pricing points eligible for day-ahead transactions in the day-ahead energy market.
- **Up To Congestion Interface Pricing Point Imports and Exports in the Day-Ahead Energy Market.** In the first three months of 2023, up to congestion transactions were net exports at five of PJM's seven interface pricing points eligible for day-ahead transactions in the day-ahead energy market.
- **Inadvertent Interchange.** In the first three months of 2023, net scheduled interchange was -8,339.9 GWh and net actual interchange was -8,281.9 GWh, a difference of 58.0 GWh. In the first three months of 2022, the difference was 24.5 GWh. This difference is inadvertent interchange.
- **Loop Flows.** In the first three months of 2023, the Northern Indiana Public Service (NIPS) Interface had the largest loop flows of any interface with -0.2 GWh of net scheduled interchange and -3,276.9 GWh of net actual interchange, a difference of 3,276.8 GWh. In the first three months of 2023, the MISO interface pricing point had the largest loop flows of any interface pricing point with 6,080.0 GWh of net scheduled interchange and 8,021.8 GWh of net actual interchange, a difference of 1,941.9 GWh.
- **Winter Storm Elliott.** Winter Storm Elliott (Elliott) had a significant impact on PJM from December 23, 2022, through December 26, 2022, primarily as a result of low temperatures. Elliott affected interchange transaction volumes, resulted in large volumes of transaction curtailments and required the sale of emergency power to neighboring balancing authorities.

1 Calculated values shown in Section 9, "Interchange Transactions," are based on unrounded, underlying data and may differ from calculations based on the rounded values in the tables.

Interactions with Bordering Areas

PJM Interface Pricing with Organized Markets

- **PJM and MISO Interface Prices.** In the first three months of 2023, the direction of the hourly flow was consistent with the real-time hourly price differences between the PJM/MISO Interface and the MISO/PJM Interface in 59.8 percent of the hours.
- **PJM and New York ISO Interface Prices.** In the first three months of 2023, the direction of the hourly flow was consistent with the real-time hourly price differences between the PJM/NYIS Interface and the NYISO/PJM proxy bus in 57.9 percent of the hours.
- **Neptune Underwater Transmission Line to Long Island, New York.** In the first three months of 2023, the hourly flow (PJM to NYISO) was consistent with the real-time hourly price differences between the PJM Neptune Interface and the NYISO Neptune bus in 87.6 percent of the hours.
- **Linden Variable Frequency Transformer (VFT) Facility.** In the first three months of 2023, the hourly flow (PJM to NYISO) was consistent with the real-time hourly price differences between the PJM Linden Interface and the NYISO Linden bus in 82.9 percent of the hours.
- **Hudson DC Line.** In the first three months of 2023, the hourly flow (PJM to NYISO) was consistent with the real-time hourly price differences between the PJM Hudson Interface and the NYISO Hudson bus in 75.2 percent of the hours.

Interchange Transaction Issues

- **PJM Transmission Loading Relief Procedures (TLRs).** PJM issued zero TLRs of level 3a or higher in the first three months of 2023, and zero such TLRs in the first three months of 2022.
- **Up To Congestion.** The average number of up to congestion bids submitted in the day-ahead energy market increased by 132.8 percent, from 33,055 bids per day in the first three months of 2022 to 76,959 bids per day in the first three months of 2023. The average cleared volume of up to congestion bids submitted in the day-ahead energy market increased by 135.2 percent, from 247,428 MWh per day in the first three months of 2022, to 582,009 MWh per day in the first three months of 2023.

Recommendations

- The MMU recommends that PJM implement rules to prevent sham scheduling. The MMU recommends that PJM apply after the fact market settlement adjustments to identified sham scheduling segments to ensure that market participants cannot benefit from sham scheduling. (Priority: High. First reported 2012. Status: Not adopted.)
- The MMU recommends that PJM implement a validation method for submitted transactions that would prohibit market participants from breaking transactions into smaller segments to defeat the interface pricing rule by concealing the true source or sink of the transaction. (Priority: Medium. First reported 2013. Status: Not adopted.)
- The MMU recommends that PJM implement a validation method for submitted transactions that would require market participants to submit transactions on paths that reflect the expected actual power flow in order to reduce unscheduled loop flows. (Priority: Medium. First reported 2013. Status: Not adopted.)
- The MMU recommends that transactions sourcing in the Western Interconnection be priced at either the MISO interface pricing point or the SOUTH interface pricing point based on the locational price impact of flows between the DC tie line point of connection with the Eastern Interconnection and PJM. (Priority: High. First reported 2020. Status: Not adopted.)
- The MMU recommends that PJM eliminate the IMO interface pricing point, and assign the transactions that originate or sink in the IESO balancing authority to the MISO interface pricing point. (Priority: Medium. First reported 2013. Status: Not adopted.)
- The MMU recommends that PJM monitor, and adjust as necessary, the weights applied to the components of the interfaces to ensure that the interface prices reflect ongoing changes in system conditions. The MMU also recommends that PJM review the mappings of external balancing

authorities to individual interface pricing points to reflect changes to the impact of the external power source on PJM tie lines as a result of system topology changes. The MMU recommends that this review occur at least annually. (Priority: Low. First reported 2009. Status: Not adopted.)

- The MMU recommends that, in order to permit a complete analysis of loop flow, FERC and NERC ensure that the identified data are made available to market monitors as well as other industry entities determined appropriate by FERC. (Priority: Medium. First reported 2003. Status: Not adopted.)
- The MMU recommends that PJM explore an interchange optimization solution with its neighboring balancing authorities that would remove the need for market participants to schedule physical transactions across seams. Such a solution would include an optimized, but limited, joint dispatch approach that uses supply curves and treats seams between balancing authorities as constraints, similar to other constraints within an LMP market. (Priority: Medium. First reported 2014. Status: Not adopted.)
- The MMU recommends that PJM permit unlimited spot market imports as well as unlimited nonfirm point to point willing to pay congestion imports and exports at all PJM interfaces in order to improve the efficiency of the market. (Priority: Medium. First reported 2012. Status: Not adopted.)
- The MMU recommends that the emergency interchange cap be replaced with a market based solution. (Priority: Low. First reported 2015. Status: Not adopted.)
- The MMU recommends that the submission deadline for real-time dispatchable transactions be modified from 1800 on the day prior, to three hours prior to the requested start time, and that the minimum duration be modified from one hour to 15 minutes. These changes would give PJM a more flexible product that could be used to meet load in the most economic manner. (Priority: Medium. First reported 2014. Status: Partially adopted, 2015.)
- The MMU recommends modifications to the FFE calculation to ensure that FFE calculations reflect the current capability of the transmission system as it evolves. The MMU recommends that the Commission set a deadline for PJM and MISO to resolve the FFE freeze date and related issues. (Priority: Medium. First reported 2019. Status: Not adopted.)
- The MMU recommends clear, explicit and detailed rules that define the conditions under which PJM will and will not recall energy from PJM capacity resources and prohibit new energy exports from PJM capacity resources. The MMU recommends that those rules define the conditions under which PJM will purchase emergency energy while at the same time not recalling energy exports from PJM capacity resources. The MMU recommends clear rules governing when PJM may recall capacity backed exports. (Priority: Medium. First reported 2010. Status: Partially adopted.)

Conclusion

Transactions between PJM and multiple balancing authorities in the Eastern Interconnection are part of a single energy market. While some of these balancing authorities are termed market areas and some are termed nonmarket areas, all electricity transactions are part of a single energy market. Nonetheless, there are significant differences between market and nonmarket areas. Market areas, like PJM, include essential features of an energy market including locational marginal pricing, financial congestion offsets (FTRs and ARRs in PJM) and transparent, least cost, security constrained economic dispatch for all available generation. Nonmarket areas do not include these features. Pricing in the market areas is transparent and pricing in the nonmarket areas is not transparent.

The MMU's recommendations related to transactions with external balancing authorities all share the goal of improving the economic efficiency of interchange transactions. The standard of comparison is an LMP market. In an LMP market, redispatch based on LMP and competitive generator offers results in an efficient dispatch and efficient prices. The goal of designing interface transaction rules should be to match the outcomes that would exist in an LMP market across the interfaces.

It is not appropriate to have special pricing agreements between PJM and any external entity. The same market pricing should apply to all transactions.

External entities wishing to receive the benefits of the PJM LMP market should join PJM.

In 2020, PJM terminated a number of interface pricing points, consistent with longstanding MMU recommendations. Following the termination of the Northwest pricing point on October 1, 2020, PJM failed to correctly map the pricing points to transactions that had been mapped to the Northwest pricing point to pricing points that are consistent with electrical impacts on the PJM system. On October 1, 2022, PJM terminated the Southeast and Southwest interface pricing points. The MMU recommends that transactions sourcing in the Western Interconnection be priced at either the MISO interface pricing point or the SOUTH interface pricing point based on the electrical impact of flows between the DC tie line point of connection with the Eastern Interconnection and PJM. The MMU continues to recommend the termination of the Ontario interface pricing point. The Ontario interface pricing point is noncontiguous to the PJM footprint that creates opportunities for market participants to engage in sham scheduling activities.

Interchange Transaction Activity

Charges and Credits Applied to Interchange Transactions

Interchange transactions are subject to various charges and credits. These charges and credits are dependent on whether the interchange transaction is submitted in the real-time or day-ahead energy market, the type of transaction, the transmission service used and whether the transaction is an import, export or wheel. Table 9-1 shows the billing line items that represent the charges and credits applied to real-time and day-ahead interchange transactions.[2]

2 For an explanation and current rate for each billing line item, see "*Quick Reference Guide to Market Settlements By Type of Business*" (February 1, 2023) <https://pjm.com/markets-and-operations/~/media/0FE1D93C5E61457185BB7652F2F18668.ashx>.

Table 9-1 Charges and credits applied to interchange transactions

	Real-Time Transactions				Day-Ahead Transactions				
Billing Item	Import (Firm or Non Firm)	Import (Spot in)	Export	Wheel	Import (Firm or Non Firm)	Import (Spot in)	Export	Wheel	Up to Congestion
Firm or Non-Firm Point-to-Point Transmission Service	X		X[1]	X[1]	X		X[1]	X[1]	
Spot Import Service		X[2]				X[2]			
Day-ahead Spot Market Energy					X	X	X		
Balancing Spot Market Energy	X	X	X						
Day-ahead Transmission Congestion					X	X	X	X	X
Balancing Transmission Congestion	X	X	X	X					X
Day-ahead Transmission Losses					X	X	X	X	X
Balancing Transmission Losses	X	X	X	X					X
PJM Scheduling, System Control and Dispatch Service - Control Area Administration	X		X	X	X		X	X	
PJM Scheduling, System Control and Dispatch Service - Market Support	X	X	X		X	X	X		X
PJM Scheduling, System Control and Dispatch Service - Advanced Second Control Center	X	X	X	X	X	X	X	X	X
PJM Scheduling, System Control and Dispatch Service - Market Support Offset	X	X	X		X	X	X		X
PJM Settlement, Inc.	X	X	X		X	X	X		X
Market Monitoring Unit (MMU) Funding	X	X	X		X	X	X		X
FERC Annual Recovery	X		X	X	X		X	X	
Organization of PJM States, Inc. (OPSI) Funding	X		X	X	X		X	X	
Synchronous Condensing			X				X		
Transmission Owner Scheduling, System Control and Dispatch Service	X		X	X	X		X	X	
Reactive Supply and Voltage Control from Generation and Other Sources Service	X		X	X	X		X	X	
Day-ahead Operating Reserve					X	X	X		X
Balancing Operating Reserve	X	X	X						X
Black Start Service	X		X	X	X		X	X	
Marginal Loss Surplus Allocation (for those paying for transmission service only)			X				X		

[1] No charge if Point of Delivery is MISO

[2] No charge for spot in transmission

Aggregate Imports and Exports

Table 9-2 shows the real-time and day-ahead scheduled interchange totals for the first three months of 2022 and 2023. In the first three months of 2023, gross imports in the day-ahead energy market were 111.7 percent of gross imports in the real-time energy market (83.7 percent in the first three months of 2022). In the first three months of 2023, gross exports in the day-ahead energy market were 104.4 percent of gross exports in the real-time energy market (89.6 percent in the first three months of 2022).

Table 9-2 Real-time and day-ahead scheduled interchange volumes (GWh): January through March, 2022 and 2023

Category	2022 (Jan-Mar)	2023 (Jan-Mar)	Percent Change
Real-Time Gross Imports	4,380.6	4,393.5	0.3%
Real-Time Gross Exports	13,839.2	12,733.3	(8.0%)
Real-Time Net Interchange	(9,458.6)	(8,339.9)	(11.8%)
Day-Ahead Gross Imports	3,665.4	4,909.5	33.9%
Day-Ahead Gross Exports	12,402.4	13,295.0	7.2%
Day-Ahead Net Interchange	(8,737.1)	(8,385.4)	(4.0%)
Monthly Average Real-Time Gross Exports	4,613.1	4,244.4	(8.0%)
Monthly Average Real-Time Gross Imports	1,460.2	1,464.5	0.3%
Monthly Average Day-Ahead Gross Exports	4,134.1	4,431.7	7.2%
Monthly Average Day-Ahead Gross Imports	1,221.8	1,636.5	33.9%

In the first three months of 2023, PJM was a monthly net exporter of energy in the real-time energy market in all months. In the first three months of 2023, PJM was a monthly net exporter of energy in the day-ahead energy market in all months (Figure 9-1).[3]

Figure 9-1 shows real-time and day-ahead import, export and net interchange volumes. The day-ahead totals include fixed, dispatchable and up to congestion transaction totals. The net interchange of up to congestion transactions are represented by the orange line.

Transactions in the day-ahead energy market create financial obligations to deliver in the real-time energy market and to pay operating reserve charges based on differences between the transaction MWh in the day-ahead and real-time energy markets times the applicable operating reserve rates. Up to congestion transactions also create financial obligations to deliver in real time, but did not pay operating reserve charges until November 1, 2020. In the first three months of 2023, the total day-ahead gross imports and exports were higher than the real-time gross imports and exports, the day-ahead imports net of up to congestion transactions were less than the real-time imports, and the day-ahead exports net of up to congestion transactions were less than real-time exports.

3 Calculated values shown in Section 9, "Interchange Transactions," are based on unrounded, underlying data and may differ from calculations based on the rounded values in the tables.

Figure 9-1 Scheduled imports and exports: January through March, 2023

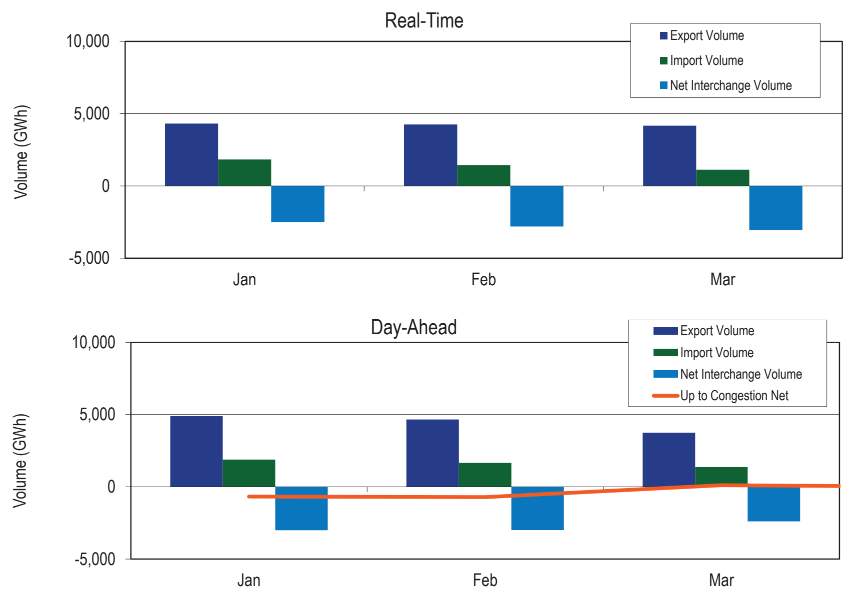
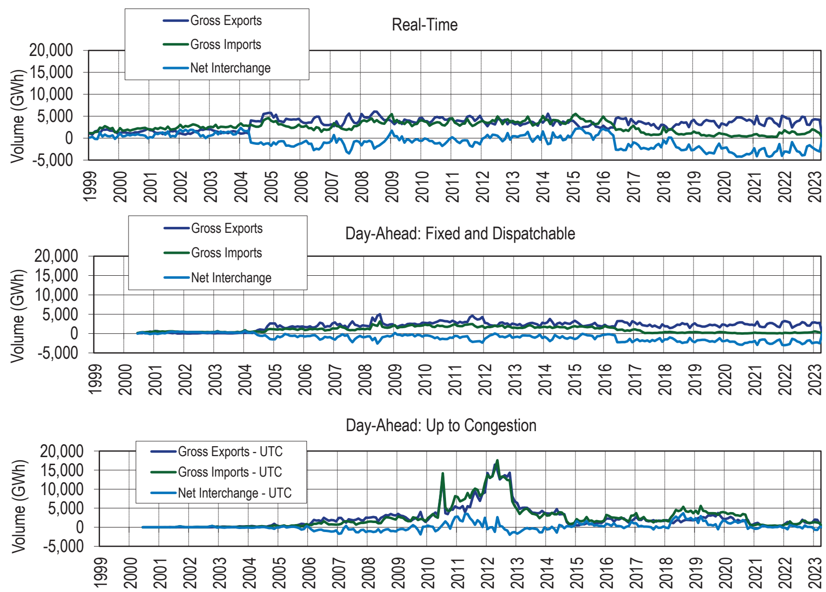


Figure 9-2 shows the real-time and day-ahead import and export volume for PJM from January 1999 through March 2023. PJM shifted from a consistent net importer of energy to relatively consistent net exporter of energy in 2004 in both the real-time and day-ahead energy markets, coincident with the expansion of the PJM footprint that included the integrations of Commonwealth Edison, American Electric Power and Dayton Power and Light into PJM. The net direction of power flows is generally a function of price differences net of transactions costs. Since the modification of the up to congestion product in September 2010, up to congestion transactions have played a significant role in power flows between PJM and external balancing authorities in the day-ahead energy market. On November 1, 2012, PJM eliminated the requirement that every up to congestion transaction include an interface pricing point as either the source or sink. As a result, the volume of import and export up to congestion transactions decreased, and the volume of internal up to congestion transactions increased. While the gross import and export volumes in the day-ahead energy market decreased, PJM has remained primarily a net exporter in the day-ahead energy market. The requirement for external capacity resources to be pseudo tied into PJM has affected the real-time and day-ahead import volumes. Prior to June 1, 2016, these units were dynamically scheduled into PJM or were block scheduled into PJM and were part of scheduled interchange as imports. Pseudo tied units are treated as internal generation and therefore do not affect interchange volume. The reduction of the import volume based on the switch to pseudo tie status contributed to PJM remaining a net exporter in the real-time and day-ahead energy markets. On February 20, 2018, FERC issued an order limiting the eligible bidding points for up to congestion transactions to hubs, residual metered load and interfaces.[4] As a result, the volume of import and export up to congestion transactions increased, contributing to PJM becoming a net importer in the day-ahead energy market starting in March 2018. On July 16, 2020, FERC issued an order directing PJM to revise uplift allocation rules to allocate uplift to up to congestion transactions.[5] The Order requires PJM to treat an up to congestion transaction, for uplift allocation purposes, as if the up to congestion transaction were equivalent to a DEC at its sink point. On November 1, 2020, PJM began allocating uplift to up to congestion transactions. As a result, the volume of up to congestion transactions decreased. In February 2021, winter storms caused significant generation outages in Texas and resulted in power outages across the Electric Reliability Council of Texas (ERCOT) region. These outages occurred between February 10, 2021, and February 27, 2021. During this time, ERCOT imported generation from neighboring regions. While PJM did not have any scheduled exports directly to the ERCOT region, PJM exports during this time increased from an average hourly export of 4,772 MW per hour between February 1 and February 10, 2021, to 7,003 MW per hour between February 10 and February 27, 2021.

On June 13, 2022, PJM experienced several intervals of shortage pricing that resulted in high LMPs during the period from 1450 (EPT) through 1800 (EPT). PJM remained a net exporter of energy throughout the period despite the fact that PJM prices were much higher than MISO prices. PJM net exports averaged 4,431 MW during hours ending 1500 (EPT) through 1800 (EPT), a slight decrease from average net exports of 5,560 MW during the hours ending 1100 (EPT) through 1400 (EPT). Market participant response to the pricing signals in this period was affected by TLRs issued by MISO, SWPP and PJM, although the curtailments of scheduled imports to PJM were relatively small compared to the net exports. Export transactions to MISO continued to flow during this period primarily on firm and grandfathered transmission service. The lack of response to relative prices on the PJM/MISO interface was consistent with the ongoing pattern that there are net exports from PJM to MISO in almost every hour, regardless of relative prices. In the first three months of 2023, flows were in the uneconomic direction on the PJM/MISO interface in 40.2 percent of all hours.

4 162 FERC ¶ 61,139.
5 172 FERC ¶ 61,046.

Figure 9-2 Scheduled import and export transaction volume history: January 1, 1999 through March 31, 2023



Real-Time Interface Imports and Exports

In the real-time energy market, scheduled imports and exports are defined by the scheduled path, which is the transmission path a market participant selects from the original source to the final sink. These scheduled flows are measured at each of PJM's interfaces with neighboring balancing authorities. Table 9-19 includes a list of active interfaces in the first three months of 2023. Figure 9-3 shows the approximate geographic location of the interfaces. In the first three months of 2023, PJM had 19 interfaces with neighboring balancing authorities. While the Linden (LIND) Interface, the Hudson (HUDS) Interface and the Neptune (NEPT) Interface are separate from the NYIS Interface, all four are interfaces between PJM and the NYISO. There are 10 separate interfaces that make up the MISO Interface between PJM and MISO. Table 9-3 through Table 9-5 show the real-time energy market scheduled interchange totals at the individual NYISO interfaces, as well as with the NYISO as a whole. Similarly, the scheduled interchange totals at the individual interfaces between PJM and MISO are shown, as well as with MISO as a whole. Net scheduled interchange in the real-time energy market is shown by interface for the first three months of 2023 in Table 9-3, while gross scheduled imports and exports are shown in Table 9-4 and Table 9-5.

In the real-time energy market, in the first three months of 2023, there were net scheduled exports at 14 of PJM's 19 interfaces. The top three net exporting interfaces in the real-time energy market accounted for 48.0 percent of the total net scheduled exports: PJM/Cinergy (CIN) with 17.7 percent, PJM/NYIS with 16.5 percent and PJM/MidAmerican Energy Company (MEC) with 13.8 percent of the net scheduled export volume. The four separate interfaces that connect PJM to the NYISO (PJM/NYIS, PJM/NEPT, PJM/HUDS and PJM/Linden (LIND)) together represented 44.3 percent of the total net PJM scheduled exports in the real-time energy market. There were net scheduled exports in the real-time energy market at eight of the 10 separate interfaces that connect PJM to MISO. Those eight exporting interfaces represented 53.1 percent of the total net PJM scheduled exports in the real-time energy market.

In the real-time energy market, in the first three months of 2023, there were net scheduled imports at four of PJM's 19 interfaces. The top importing interface in the real-time energy market was the PJM/Duke (DUK) Interface, which accounted for 53.0 percent of the total net scheduled import volume.[6] The four separate interfaces that connect PJM to the NYISO (PJM/NYIS, PJM/NEPT, PJM/HUDS and PJM/Linden (LIND)) had net scheduled exports in the real-time energy market. There were net scheduled imports in the real-time energy market at one of the 10 separate interfaces that connect PJM to MISO (Ameren-Illinois (AMIL)). This importing interface represented 10.8 percent of the total net PJM scheduled imports in the real-time energy market.

6 In the real-time energy market, one PJM interface had a net interchange of zero (PJM/City Water Light & Power (CWLP)). CWLP is a balancing authority on the western side of MISO.

Table 9-3 Real-time scheduled net interchange volume by interface (GWh): January through March, 2023

	Jan	Feb	Mar	Total
CPLE	(16.9)	(9.3)	(25.7)	(51.9)
CPLW	1.6	6.0	0.0	7.6
DUK	656.3	545.1	329.9	1,531.3
LGEE	(93.9)	(58.7)	(84.2)	(236.9)
MISO	(1,695.2)	(2,062.9)	(1,895.1)	(5,653.2)
ALTE	(216.7)	(280.0)	(288.1)	(784.8)
ALTW	(6.5)	(5.2)	(15.3)	(27.0)
AMIL	190.8	28.1	91.6	310.6
CIN	(668.1)	(690.4)	(626.9)	(1,985.4)
CWLP	0.0	0.0	0.0	0.0
IPL	(21.0)	(23.6)	(22.0)	(66.6)
MEC	(544.6)	(506.8)	(497.6)	(1,549.0)
MECS	(409.9)	(525.6)	(478.0)	(1,413.5)
NIPS	0.1	(0.0)	(0.2)	(0.2)
WEC	(19.1)	(59.5)	(58.6)	(137.2)
NYISO	(1,780.0)	(1,607.1)	(1,587.9)	(4,974.9)
HUDS	(379.9)	(291.0)	(400.6)	(1,071.5)
LIND	(207.4)	(194.3)	(227.2)	(628.9)
NEPT	(487.6)	(440.1)	(491.6)	(1,419.3)
NYIS	(705.1)	(681.7)	(468.5)	(1,855.2)
TVA	437.0	379.2	221.8	1,038.0
Total	(2,491.1)	(2,807.6)	(3,041.2)	(8,339.9)

Table 9-4 Real-time scheduled gross import volume by interface (GWh): January through March, 2023

	Jan	Feb	Mar	Total
CPLE	6.0	27.1	18.3	51.4
CPLW	1.6	6.0	0.0	7.6
DUK	729.3	625.1	427.0	1,781.4
LGEE	5.9	2.1	3.0	11.1
MISO	440.2	207.0	240.3	887.5
ALTE	12.0	20.0	20.2	52.2
ALTW	0.0	0.0	0.0	0.0
AMIL	196.3	47.8	102.3	346.4
CIN	20.1	40.9	22.9	83.9
CWLP	0.0	0.0	0.0	0.0
IPL	3.1	3.2	1.5	7.8
MEC	23.4	18.1	22.4	63.9
MECS	138.1	54.1	20.9	213.1
NIPS	0.1	(0.0)	(0.2)	(0.2)
WEC	47.2	22.9	50.3	120.4
NYISO	125.4	106.2	126.1	357.7
HUDS	0.0	0.0	0.0	0.0
LIND	0.0	0.1	0.0	0.1
NEPT	0.0	0.1	0.1	0.1
NYIS	125.4	106.0	126.0	357.4
TVA	517.7	467.5	311.5	1,296.7
Total	1,826.2	1,441.1	1,126.2	4,393.5

Table 9-5 Real-time scheduled gross export volume by interface (GWh): January through March, 2023

	Jan	Feb	Mar	Total
CPLE	22.9	36.4	44.0	103.3
CPLW	0.0	0.0	0.0	0.0
DUK	73.0	80.0	97.1	250.0
LGEE	99.9	60.8	87.2	248.0
MISO	2,135.4	2,269.9	2,135.4	6,540.7
ALTE	228.8	300.0	308.3	837.0
ALTW	6.5	5.2	15.3	27.0
AMIL	5.5	19.7	10.7	35.9
CIN	688.1	731.3	649.8	2,069.2
CWLP	0.0	0.0	0.0	0.0
IPL	24.1	26.8	23.5	74.4
MEC	568.0	524.9	520.0	1,612.9
MECS	548.0	579.7	498.9	1,626.6
NIPS	0.0	0.0	0.0	0.0
WEC	66.4	82.4	108.9	257.7
NYISO	1,905.4	1,713.3	1,714.0	5,332.6
HUDS	379.9	291.0	400.6	1,071.5
LIND	207.4	194.4	227.2	629.1
NEPT	487.6	440.2	491.7	1,419.4
NYIS	830.5	787.7	594.5	2,212.6
TVA	80.7	88.3	89.7	258.7
Total	4,317.2	4,248.7	4,167.4	12,733.3

Real-Time Interface Pricing Point Imports and Exports

Interfaces differ from interface pricing points. An interface is a point of interconnection between PJM and a neighboring balancing authority which market participants may designate as a path on which scheduled imports or exports will flow.[7] An interface pricing point defines the price at which transactions are priced, and is based on the path of the actual, physical transfer of energy. While a market participant designates a scheduled path from a generation control area (GCA) to a load control area (LCA), this path reflects the scheduled path as defined by the transmission reservations only, and may not reflect how the energy actually flows from the GCA to LCA. For example, the import transmission path from LG&E Energy, L.L.C. (LGEE), through MISO and into PJM would show the transfer of power into PJM at the PJM/MISO Interface based on the scheduled path of the transaction. However, the physical flow of energy does not enter the PJM footprint at the PJM/MISO Interface, but enters PJM at the southern boundary. For this reason, PJM prices an import with the GCA of LGEE at the SOUTH interface pricing point rather than the MISO pricing point.

Interfaces differ from interface pricing points. The challenge is to create interface prices, composed of external pricing points, which accurately represent the locational price impact of flows between PJM and external sources of energy and that reflect the underlying economic fundamentals across balancing authority borders.[8]

Transactions can be scheduled to an interface based on a contract transmission path, but pricing points are developed and applied based on the estimated electrical impact of the external power source on PJM tie lines, regardless of the contract transmission path.[9] PJM establishes prices for transactions with external balancing authorities by assigning interface pricing points to individual balancing authorities based on the generation control area and load control area as specified on the NERC Tag. Dynamic interface pricing calculations use actual system conditions to determine a set of weights for each external pricing point in an interface price definition. The weights are designed so that the interface price reflects actual system conditions. However, the weights are an approximation given the complexity of the transmission network outside PJM and the dynamic nature of power flows. Table 9-20 presents the interface pricing points used in the first three months of 2023. On October 21, 2020, PJM updated the mappings of external balancing authorities to individual pricing points. Figure 9-4 shows a map of the default interface pricing point assignments for all external balancing authorities. Figure 9-4 shows that the balancing authorities in the Western Interconnection are mapped to either the MISO interface pricing point or the SOUTH interface pricing point. This determination was made by PJM based on geographic location rather than the electrical impact on the PJM system. When power is scheduled across a DC tie line, its effects on the PJM system are as if a generator is located at the point in the Eastern Interconnection where the DC

7 There are multiple paths between any generation and load balancing authority. Market participants select the path based on transmission service availability and the transmission costs for moving energy from generation to load and interface prices.

8 See the *2007 State of the Market Report for PJM*, Volume II, Appendix D, "Interchange Transactions," for a more complete discussion of the development of pricing points.

9 See "Interface Pricing Point Assignment Methodology," (June 1, 2021) <http://www.pjm.com/~/media/etools/exschedule/interface-pricing-point-assignment-methodology.ashx>. PJM periodically updates these definitions on its website.

tie line connects. The electrical impact on PJM tie lines from sources in the Western Interconnection differ based on the relevant DC tie line and could vary from the MISO interface pricing point to the SOUTH interface pricing point. The MMU recommends that transactions sourcing in the Western Interconnection be priced at either the MISO interface pricing point or the SOUTH interface pricing point based on the locational price impact of flows between the DC tie line point of connection with the Eastern Interconnection and PJM rather than geographical location. The MMU recommends that PJM review the mappings of external balancing authority pricing points at least annually to reflect the fact that changes to the system topology can affect the electrical impact of external power sources on PJM.

The MMU has made multiple recommendations to either retire or consolidate interface pricing points used by PJM. The reasons for those recommendations include: pricing points that could no longer be used to price actual transactions; pricing points that were inappropriately used to support special agreements; pricing points that were treated as multiple pricing points when they were a single pricing point; and pricing points that were noncontiguous to the PJM footprint that created opportunities for sham scheduling. Table 9-6 shows the interface pricing points, the recommendation and the date the recommendation was adopted.

Table 9-6 Interface pricing point recommendations and dates adopted

Interface Pricing Point	Recommendation	Date Adopted
IMO	Retire Pricing Point - Noncontiguous	
Southeast (Real-Time Market)	Retire Pricing Point - Support Special Agreements	1-Oct-2022
Southwest (Real-Time Market)	Retire Pricing Point - Support Special Agreements	1-Oct-2022
SOUTHEXP	Consolidate Pricing Points	1-Jun-2021
SOUTHIMP	Consolidate Pricing Points	1-Jun-2021
Southeast	Retire Pricing Point - Support Special Agreements	15-Apr-2021
Southwest	Retire Pricing Point - Support Special Agreements	15-Apr-2021
NCMPAEXP	Retire Pricing Point - Preferential Treatment	3-Nov-2020
NCMPAIMP	Retire Pricing Point - Preferential Treatment	3-Nov-2020
Northwest	Retire Pricing Point - Noncontiguous	1-Oct-2020
CPLEEXP	Retire Pricing Point - Preferential Treatment	1-Jun-2020
CPLEIMP	Retire Pricing Point - Preferential Treatment	1-Jun-2020
DUKEXP	Retire Pricing Point - Preferential Treatment	1-Jun-2020
DUKIMP	Retire Pricing Point - Preferential Treatment	1-Jun-2020
NIPSCO	Retire Pricing Point - Obsolete (Integration into MISO)	1-Jun-2020
OVEC	Retire Pricing Point - Obsolete (Integration into PJM)	1-Dec-2018

The interface pricing method implies that the weighting factors reflect the actual system flows in a dynamic manner. In fact, the weightings are static, and are modified by PJM only occasionally.[10] The MMU recommends that PJM monitor, and adjust as necessary, the weights applied to the components of the interfaces to ensure that the interface prices reflect ongoing changes in system conditions.

The contract transmission path only reflects the path of energy into or out of PJM to one neighboring balancing authority. The NERC Tag requires the complete path to be specified from the generation control area (GCA) to the load control area (LCA), but participants do not always do so. The NERC Tag path is used by PJM to determine the interface pricing point that PJM assigns to the transaction. This approach will correctly identify the interface pricing point only if the market participant provides the complete path in the Tag.

In the real-time energy market, in the first three months of 2023, there were net scheduled exports at five of PJM's seven interface pricing points eligible for real-time transactions. The top three net exporting interface pricing points in the real-time energy market accounted for 84.9 percent of the total net scheduled exports: PJM/MISO with 55.9 percent, PJM/NYIS with 16.4 percent and PJM/NEPTUNE with 12.6 percent of the net scheduled export volume. The four separate interface pricing points that connect PJM to the NYISO (PJM/NYIS, PJM/NEPTUNE, PJM/HUDSONTP and PJM/LINDENVFT) together represented 44.1 percent of the total net PJM scheduled exports in the real-time energy market.

In the real-time energy market, in the first three months of 2023, there were net scheduled imports at two of PJM's seven interface pricing points eligible for real-time transactions. The top importing interface pricing point in the real-time energy market was the PJM/SOUTH interface pricing point, which accounted for 92.6 percent of the total net scheduled import volume. The four separate interface pricing points that connect PJM to the NYISO (PJM/NYIS, PJM/NEPTUNE, PJM/HUDSONTP and PJM/LINDENVFT) had net scheduled exports in the real-time energy market.

10 On June 1, 2015, PJM began using a dynamic weighting factor in the calculation for the Ontario interface pricing point.

Table 9-7 Real-time scheduled net interchange volume by interface pricing point (GWh): January through March, 2023

	Jan	Feb	Mar	Total
IMO	130.9	67.4	19.0	217.2
MISO	(2,057.0)	(2,173.1)	(2,068.2)	(6,298.3)
NYISO	(1,779.1)	(1,607.0)	(1,587.8)	(4,973.9)
HUDSONTP	(379.9)	(291.0)	(400.6)	(1,071.5)
LINDENVFT	(207.4)	(194.3)	(227.2)	(628.9)
NEPTUNE	(487.6)	(440.1)	(491.6)	(1,419.3)
NYIS	(704.2)	(681.6)	(468.4)	(1,854.2)
SOUTH	1,214.1	905.1	595.8	2,715.0
Total	(2,491.1)	(2,807.6)	(3,041.2)	(8,339.9)

Table 9-8 Real-time scheduled gross import volume by interface pricing point (GWh): January through March, 2023

	Jan	Feb	Mar	Total
IMO	134.7	68.8	19.4	223.0
MISO	67.9	81.2	61.8	210.9
NYISO	125.0	106.1	126.1	357.2
HUDSONTP	0.0	0.0	0.0	0.0
LINDENVFT	0.0	0.1	0.0	0.1
NEPTUNE	0.0	0.1	0.1	0.1
NYIS	125.0	105.9	126.0	356.9
SOUTH	1,498.5	1,185.0	918.9	3,602.4
Total	1,826.2	1,441.1	1,126.2	4,393.5

Table 9-9 Real-time scheduled gross export volume by interface pricing point (GWh): January through March, 2023

	Jan	Feb	Mar	Total
IMO	3.8	1.5	0.4	5.7
MISO	2,124.9	2,254.3	2,130.0	6,509.2
NYISO	1,904.1	1,713.1	1,713.9	5,331.1
HUDSONTP	379.9	291.0	400.6	1,071.5
LINDENVFT	207.4	194.4	227.2	629.1
NEPTUNE	487.6	440.2	491.7	1,419.4
NYIS	829.2	787.5	594.4	2,211.1
SOUTH	284.3	279.9	323.1	887.4
Total	4,317.2	4,248.7	4,167.4	12,733.3

Day-Ahead Interface Imports and Exports

In the day-ahead energy market, as in the real-time energy market, scheduled imports and exports are determined by the scheduled path, which is the transmission path a market participant selects from the original source to the final sink. Entering external energy transactions in the day-ahead energy market requires fewer steps than in the real-time energy market. Market participants need to acquire a valid, willing to pay congestion (WPC) OASIS reservation to prove that their day-ahead schedule could be supported in the real-time energy market.[11] Day-ahead energy market schedules need to be cleared through the day-ahead energy market process in order to become an approved schedule. The day-ahead energy market transactions are financially binding, but will not physically flow unless they are also submitted in the real-time energy market. In the day-ahead energy market, a market participant is not required to acquire a ramp reservation, a NERC Tag, or to go through a neighboring balancing authority checkout process.

There are three types of day-ahead external energy transactions: fixed; up to congestion; and dispatchable.[12]

In the day-ahead energy market, transaction sources and sinks are determined solely by market participants. In Table 9-10, Table 9-11, and Table 9-12, the scheduled interface designation is determined by the transmission reservation that was acquired and associated with the day-ahead market transaction, and does not bear any necessary relationship to the pricing point designation selected at the time the transaction is submitted to PJM in real time. For example, if market participants want to import energy from the Southwest Power Pool (SPP) to PJM, they are likely to choose a scheduled path with the fewest transmission providers along the path and therefore the lowest transmission costs for the transaction, regardless of whether the resultant path is related to the physical flow of power. The lowest cost transmission path runs from SPP, through MISO, and into PJM, requiring only three transmission reservations, two of which are available at no cost (MISO transmission would be free based on the regional through and out rates, and the PJM transmission would be free, if using spot import transmission). Any other transmission path

11 Effective September 17, 2010, up to congestion transactions no longer required a willing to pay congestion transmission reservation.

12 See the *2010 State of the Market Report for PJM*, Volume II, Section 4, "Interchange Transactions," for details.

entering PJM, where the generating control area is to the south, would require the market participant to acquire transmission through nonmarket balancing authorities, and thus incur additional transmission costs. PJM's interface pricing method recognizes that transactions sourcing in SPP and sinking in PJM will create flows across the southern border and prices those transactions at the SOUTH interface price. As a result, a market participant who plans to submit a transaction from SPP to PJM may have a transmission reservation with a point of receipt of MISO and a point of delivery of PJM but may select SOUTH as the import pricing point when submitting the transaction in the day-ahead energy market. In the scheduled interface tables, the import transaction would appear as scheduled through the MISO Interface, and in the scheduled interface pricing point tables, the import transaction would appear as scheduled through the SOUTH interface pricing point, which reflects the expected power flow.

Table 9-10 through Table 9-12 show the day-ahead scheduled interchange totals at the individual interfaces. Net scheduled interchange in the day-ahead energy market is shown by interface for the first three months of 2023 in Table 9-10, while gross scheduled imports and exports are shown in Table 9-11 and Table 9-12.

In the day-ahead energy market, in the first three months of 2023, there were net scheduled exports at 12 of PJM's 19 interfaces. The top three net exporting interfaces in the day-ahead energy market accounted for 57.0 percent of the total net scheduled exports: PJM/NYIS with 22.0 percent, PJM/Neptune (NEPT) with 18.1 percent and PJM/MidAmerican Energy Company (MEC) with 16.9 percent of the net scheduled export volume. The four separate interfaces that connect PJM to the NYISO (PJM/NYIS, PJM/NEPT, PJM/HUDS and PJM/Linden (LIND)) together represented 53.1 percent of the total net PJM scheduled exports in the day-ahead energy market. In the first three months of 2023, there were net exports in the day-ahead energy market at six of the 10 separate interfaces that connect PJM to MISO. Those six interfaces represented 40.8 percent of the total net PJM exports in the day-ahead energy market.

In the day-ahead energy market, in the first three months of 2023, there were net scheduled imports at two of PJM's 19 interfaces. The top importing interface in the day-ahead energy market was the PJM/Duke (DUK) Interface, which accounted for 99.8 percent of the net scheduled import volume. The four separate interfaces that connect PJM to the NYISO (PJM/NYIS, PJM/NEPT, PJM/HUDS and PJM/Linden (LIND)) had net scheduled exports in the day-ahead energy market. In the first three months of 2023, there were net imports in the day-ahead energy market at none of the 10 separate interfaces that connect PJM to MISO.[13]

Table 9-10 Day-ahead scheduled net interchange volume by interface (GWh): January through March, 2023

	Jan	Feb	Mar	Total
CPLE	(21.3)	(26.7)	(32.6)	(80.6)
CPLW	1.4	0.0	0.0	1.4
DUK	337.9	328.7	226.4	893.0
LGEE	(106.3)	(82.0)	(116.5)	(304.8)
MISO	(1,066.7)	(1,073.6)	(1,124.0)	(3,264.3)
ALTE	(138.6)	(146.9)	(148.2)	(433.6)
ALTW	(6.2)	(5.1)	(15.5)	(26.8)
AMIL	0.0	0.0	0.0	0.0
CIN	(207.8)	(371.3)	(342.9)	(921.9)
CWLP	0.0	0.0	0.0	0.0
IPL	0.0	0.0	0.0	0.0
MEC	(490.1)	(430.1)	(433.1)	(1,353.3)
MECS	(167.1)	(52.8)	(91.2)	(311.2)
NIPS	0.0	0.0	0.0	0.0
WEC	(56.8)	(67.4)	(93.2)	(217.4)
NYISO	(1,497.5)	(1,381.9)	(1,368.0)	(4,247.4)
HUDS	(367.9)	(288.0)	(381.4)	(1,037.4)
LIND	0.0	0.0	0.0	0.0
NEPT	(496.6)	(454.3)	(500.6)	(1,451.5)
NYIS	(633.0)	(639.6)	(486.0)	(1,758.6)
TVA	24.3	(48.7)	(84.5)	(108.9)
Total without Up To Congestion	(2,328.3)	(2,284.1)	(2,499.1)	(7,111.6)
Up To Congestion	(670.9)	(713.2)	110.2	(1,273.9)
Total	(2,999.2)	(2,997.3)	(2,388.9)	(8,385.4)

13 In the day-ahead energy market, five PJM interfaces had a net interchange of zero (PJM/Ameren-Illinois (AMIL), PJM/City Water Light & Power (CWLP), PJM Illinois Power and Light (IPL), Northern Indiana Public Service (NIPS) and PJM/Linden (LIND)).

Table 9-11 Day-ahead scheduled gross import volume by interface (GWh): January through March, 2023

	Jan	Feb	Mar	Total
CPLE	0.0	1.9	5.7	7.6
CPLW	1.4	0.0	0.0	1.4
DUK	362.7	337.2	246.3	946.2
LGEE	0.0	0.0	0.0	0.0
MISO	82.0	74.1	20.1	176.2
ALTE	4.7	19.5	10.5	34.7
ALTW	0.0	0.0	0.0	0.0
AMIL	0.0	0.0	0.0	0.0
CIN	15.6	27.8	9.6	53.0
CWLP	0.0	0.0	0.0	0.0
IPL	0.0	0.0	0.0	0.0
MEC	0.0	0.0	0.0	0.0
MECS	57.7	23.6	0.0	81.4
NIPS	0.0	0.0	0.0	0.0
WEC	4.0	3.2	0.0	7.2
NYISO	5.4	0.2	0.9	6.5
HUDS	0.0	0.0	0.0	0.0
LIND	0.0	0.0	0.0	0.0
NEPT	0.0	0.0	0.0	0.0
NYIS	5.4	0.2	0.9	6.5
TVA	99.0	20.6	2.3	121.8
Total without Up To Congestion	550.5	434.0	275.3	1,259.8
Up To Congestion	1,336.9	1,225.9	1,086.9	3,649.7
Total	1,887.5	1,659.8	1,362.2	4,909.5

Table 9-12 Day-ahead scheduled gross export volume by interface (GWh): January through March, 2023

	Jan	Feb	Mar	Total
CPLE	21.3	28.6	38.3	88.2
CPLW	0.0	0.0	0.0	0.0
DUK	24.9	8.4	19.8	53.2
LGEE	106.3	82.0	116.5	304.8
MISO	1,148.7	1,147.7	1,144.1	3,440.5
ALTE	143.3	166.3	158.7	468.3
ALTW	6.2	5.1	15.5	26.8
AMIL	0.0	0.0	0.0	0.0
CIN	223.3	399.1	352.5	974.9
CWLP	0.0	0.0	0.0	0.0
IPL	0.0	0.0	0.0	0.0
MEC	490.1	430.1	433.1	1,353.3
MECS	224.9	76.5	91.2	392.6
NIPS	0.0	0.0	0.0	0.0
WEC	60.8	70.5	93.2	224.5
NYISO	1,503.0	1,382.1	1,368.9	4,253.9
HUDS	367.9	288.0	381.4	1,037.4
LIND	0.0	0.0	0.0	0.0
NEPT	496.6	454.3	500.6	1,451.5
NYIS	638.5	639.7	486.9	1,765.1
TVA	74.7	69.3	86.8	230.7
Total without Up To Congestion	2,878.9	2,718.1	2,774.4	8,371.4
Up To Congestion	2,007.8	1,939.0	976.7	4,923.6
Total	4,886.7	4,657.1	3,751.1	13,295.0

Day-Ahead Interface Pricing Point Imports and Exports

Table 9-13 through Table 9-18 show the day-ahead scheduled interchange totals at the interface pricing points. In the first three months of 2023, up to congestion transactions accounted for 74.3 percent of all scheduled import MW transactions and 37.0 percent of all scheduled export MW transactions in the day-ahead energy market. The day-ahead net scheduled interchange in the first three months of 2023, including up to congestion transactions, is shown by interface pricing point in Table 9-13. Scheduled up to congestion transactions by interface pricing point in the first three months of 2023 are shown in Table 9-14. Day-ahead gross scheduled imports and exports, including up to congestion transactions, are shown in Table 9-15 and Table

9-17, while gross scheduled import and export up to congestion transactions are shown in Table 9-16 and Table 9-18.

Maintaining outdated definitions of interface pricing points is unnecessary, inconsistent with the tariff and creates artificial opportunities for gaming by virtual transactions and FTRs. PJM should immediately eliminate interface pricing points when changes to the market mean that the pricing points can no longer be used to price actual transactions and do not reflect actual price formation.

In the day-ahead energy market, in the first three months of 2023, there were net scheduled exports at six of PJM's seven interface pricing points eligible for day-ahead transactions. The top three net exporting interface pricing points in the day-ahead energy market accounted for 82.2 percent of the total net scheduled exports: PJM/MISO with 33.1 percent, PJM/NYIS with 32.4 percent and PJM/Neptune (NEPT) with 16.7 percent of the net scheduled export volume. The four separate interface pricing points that connect PJM to the NYISO (PJM/NYIS, PJM/NEPTUNE, PJM/HUDSONTP and PJM/LINDENVFT) together represented 64.5 percent of the total net PJM scheduled exports in the day-ahead energy market.

In the day-ahead energy market, in the first three months of 2023, there were net scheduled imports at one of PJM's seven interface pricing points eligible for day-ahead transactions. The top importing interface pricing point in the day-ahead energy market was the PJM/SOUTH interface pricing point, which accounted for 100.0 percent of the net scheduled import volume. The four separate interface pricing points that connect PJM to the NYISO (PJM/NYIS, PJM/NEPTUNE, PJM/HUDSONTP and PJM/LINDENVFT) had net scheduled exports in the day-ahead energy market.

In the day-ahead energy market, in the first three months of 2023, up to congestion transactions had net scheduled exports at five of PJM's seven interface pricing points eligible for day-ahead transactions. The top three net exporting interface pricing points eligible for up to congestion transactions accounted for 85.9 percent of the total net up to congestion scheduled exports: PJM/NYIS with 53.0 percent, PJM/SOUTH with 17.7 percent and PJM/Ontario Independent Electricity System Operator (IMO) with 15.3 percent of the net up to congestion scheduled export volume. The four separate interface pricing points that connect PJM to the NYISO (PJM/NYIS, PJM/NEPTUNE, PJM/HUDSONTP and PJM/LINDENVFT) together represented 67.1 percent of the total net scheduled up to congestion exports in the day-ahead energy market. However, the PJM/NEPTUNE interface pricing point had net up to congestion scheduled imports in the day-ahead energy market.

In the day-ahead energy market, in the first three months of 2023, up to congestion transactions had net scheduled imports at two of PJM's seven interface pricing points eligible for day-ahead transactions. The top importing interface pricing points eligible for up to congestion transactions accounted for 93.3 percent of the total up to congestion scheduled imports: PJM/MISO with 93.3 percent of the net up to congestion scheduled import volume. The four separate interface pricing points that connect PJM to the NYISO (PJM/NYIS, PJM/NEPTUNE, PJM/HUDSONTP and PJM/LINDENVFT) together represented 6.7 percent of the total net scheduled up to congestion imports in the day-ahead energy market. However, the PJM/HUDSONTP, PJM/LINDENVFT and PJM/NYIS interface pricing points had net up to congestion scheduled exports in the day-ahead energy market.

Table 9-13 Day-ahead scheduled net interchange volume by interface pricing point (GWh): January through March, 2023

	Jan	Feb	Mar	Total
IMO	(69.2)	(62.4)	(71.5)	(203.2)
MISO	(1,114.9)	(835.6)	(851.8)	(2,802.4)
NYISO	(1,900.4)	(1,905.4)	(1,652.9)	(5,458.7)
HUDSONTP	(464.1)	(385.0)	(439.3)	(1,288.4)
LINDENVFT	5.6	12.6	(36.1)	(17.9)
NEPTUNE	(518.5)	(407.8)	(487.0)	(1,413.4)
NYIS	(923.4)	(1,125.2)	(690.4)	(2,739.1)
SOUTH	85.3	(193.9)	187.4	78.8
Total	(2,999.2)	(2,997.3)	(2,388.9)	(8,385.4)

Table 9-14 Up to congestion scheduled net interchange volume by interface pricing point (GWh): January through March, 2023

	Jan	Feb	Mar	Total
IMO	(127.0)	(86.0)	(71.5)	(284.5)
MISO	9.5	271.2	270.5	551.3
NYISO	(402.9)	(523.5)	(284.9)	(1,211.3)
HUDSONTP	(96.2)	(97.0)	(51.6)	(244.7)
LINDENVFT	5.6	12.6	(36.1)	(17.9)
NEPTUNE	(20.2)	46.4	13.6	39.9
NYIS	(292.1)	(485.6)	(210.8)	(988.5)
SOUTH	(150.6)	(374.9)	196.1	(329.3)
Total Interfaces	(670.9)	(713.2)	110.2	(1,273.9)
INTERNAL	14,637.5	13,440.9	16,527.6	44,606.0
Total	13,966.6	12,727.7	16,637.8	43,332.1

Table 9-15 Day-ahead scheduled gross import volume by interface pricing point (GWh): January through March, 2023

	Jan	Feb	Mar	Total
IMO	101.5	61.5	19.3	182.3
MISO	734.1	655.6	483.1	1,872.8
NYISO	108.3	177.2	124.3	409.8
HUDSONTP	16.5	23.0	30.0	69.5
LINDENVFT	44.8	39.8	32.5	117.2
NEPTUNE	17.9	76.4	32.7	126.9
NYIS	29.2	38.0	29.0	96.2
SOUTH	943.6	765.4	735.6	2,444.6
Total	1,887.5	1,659.8	1,362.2	4,909.5

Table 9-16 Up to congestion scheduled gross import volume by interface pricing point (GWh): January through March, 2023

	Jan	Feb	Mar	Total
IMO	43.8	37.9	19.3	100.9
MISO	709.8	614.8	463.0	1,787.6
NYISO	102.9	177.0	123.4	403.3
HUDSONTP	16.5	23.0	30.0	69.5
LINDENVFT	44.8	39.8	32.5	117.2
NEPTUNE	17.9	76.4	32.7	126.9
NYIS	23.7	37.9	28.1	89.7
SOUTH	480.5	396.1	481.3	1,357.9
Total Interfaces	1,336.9	1,225.9	1,086.9	3,649.7

Table 9-17 Day-ahead scheduled gross export volume by interface pricing point (GWh): January through March, 2023

	Jan	Feb	Mar	Total
IMO	170.7	123.9	90.8	385.5
MISO	1,849.0	1,491.2	1,334.9	4,675.2
NYISO	2,008.7	2,082.6	1,777.2	5,868.5
HUDSONTP	480.6	408.0	469.3	1,357.9
LINDENVFT	39.2	27.2	68.7	135.1
NEPTUNE	536.4	484.2	519.8	1,540.3
NYIS	952.6	1,163.2	719.5	2,835.3
SOUTH	858.3	959.4	548.2	2,365.8
Total	4,886.7	4,657.1	3,751.1	13,295.0

Table 9-18 Up to congestion scheduled gross export volume by interface pricing point (GWh): January through March, 2023

	Jan	Feb	Mar	Total
IMO	170.7	123.9	90.8	385.5
MISO	700.3	343.6	192.4	1,236.3
NYISO	505.7	700.5	408.3	1,614.6
HUDSONTP	112.6	120.0	81.6	314.2
LINDENVFT	39.2	27.2	68.7	135.1
NEPTUNE	38.0	29.9	19.1	87.1
NYIS	315.8	523.5	238.9	1,078.2
SOUTH	631.1	771.0	285.2	1,687.3
Total Interfaces	2,007.8	1,939.0	976.7	4,923.6

Table 9-19 Active scheduling interfaces: January through March, 2023[14]

	Jan	Feb	Mar
ALTE	Active	Active	Active
ALTW	Active	Active	Active
AMIL	Active	Active	Active
CIN	Active	Active	Active
CPLE	Active	Active	Active
CPLW	Active	Active	Active
CWLP	Active	Active	Active
DUK	Active	Active	Active
HUDS	Active	Active	Active
IPL	Active	Active	Active
LGEE	Active	Active	Active
LIND	Active	Active	Active
MEC	Active	Active	Active
MECS	Active	Active	Active
NEPT	Active	Active	Active
NIPS	Active	Active	Active
NYIS	Active	Active	Active
TVA	Active	Active	Active
WEC	Active	Active	Active

Figure 9-3 PJM's footprint and its external scheduling interfaces

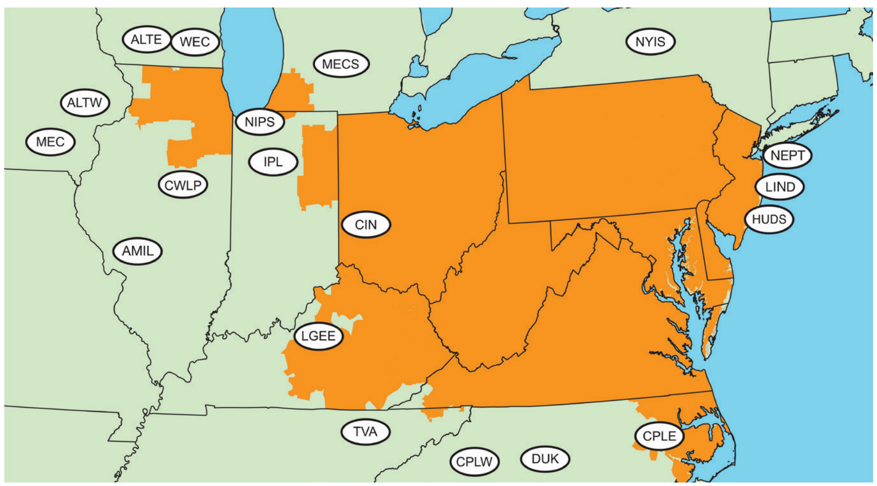
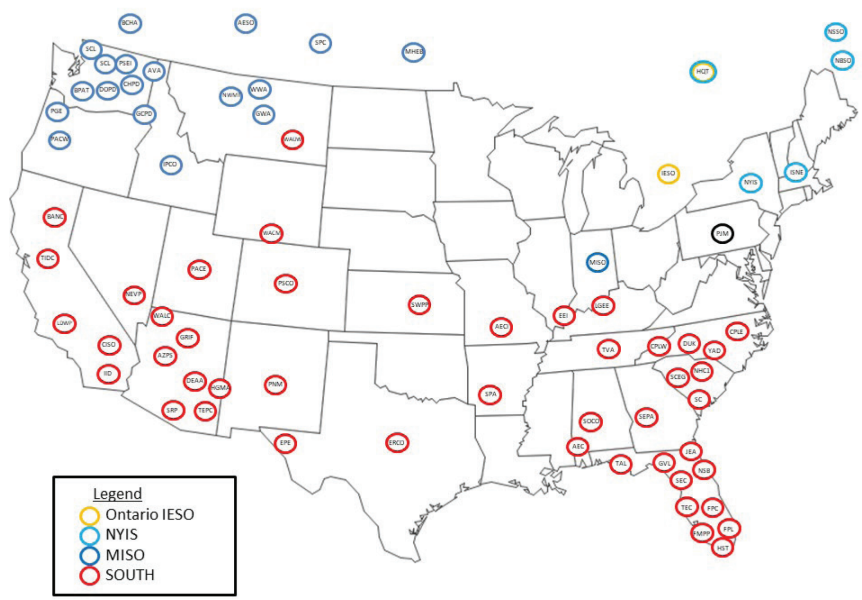


Table 9-20 Active scheduled interface pricing points: January through March, 2023

	Jan	Feb	Mar
HUDSONTP	Active	Active	Active
LINDENVFT	Active	Active	Active
MISO	Active	Active	Active
NEPTUNE	Active	Active	Active
NYIS	Active	Active	Active
Ontario IESO	Active	Active	Active
SOUTH	Active	Active	Active

Figure 9-4 External balancing authority default interface pricing point assignments



14 On July 2, 2012, Duke Energy Corp. (DUK) completed a merger with Progress Energy Inc. (CPLE and CPLW). As of March 31, 2023, DUK, CPLE and CPLW continued to operate as separate balancing authorities, and are still defined as distinct interfaces in the PJM energy market.

Loop Flows

Actual energy flows are the real-time metered power flows at an interface for a defined period. The comparable scheduled flows are the real-time power flows scheduled at an interface for a defined period. Inadvertent interchange is the difference between the total actual flows for the PJM system (net actual interchange) and the total scheduled flows for the PJM system (net scheduled interchange) for a defined period. Loop flows are the difference between actual and scheduled power flows at a specific interface. Loop flows can exist at the same time that inadvertent interchange is zero. For example, actual imports could exceed scheduled imports at one interface and actual exports could exceed scheduled exports at another interface by the same amount. The result is loop flow, despite the fact that system actual and scheduled power flow net to a zero difference.[15]

Loop flows result, in part, from a mismatch between incentives to use a particular scheduled transmission path and the market-based price differentials at interface pricing points that result from the actual physical flows on the transmission system.

PJM's approach to interface pricing attempts to match prices with physical power flows and their impacts on the transmission system. For example, if market participants want to import energy from the Southwest Power Pool (SPP) to PJM, they are likely to choose a scheduled path with the fewest transmission providers along the path and therefore the lowest transmission costs for the transaction, regardless of whether the resultant path is related to the physical flow of power. The lowest cost transmission path runs from SPP, through MISO, and into PJM, requiring only three transmission reservations, two of which are available at no cost (MISO transmission would be free based on the regional through and out rates, and the PJM transmission would be free, if using spot import transmission). Any other transmission path entering PJM, where the generating control area is to the south, would require the market participant to acquire transmission through nonmarket balancing authorities, and thus incur additional transmission costs. PJM's interface pricing method recognizes that transactions sourcing in SPP and sinking in PJM will create flows across the southern border and prices those transactions at the SOUTH interface price. As a result, the transaction is priced appropriately, but a difference between scheduled and actual flows is created at PJM's borders. For example, if a 100 MW transaction were submitted, there would be 100 MW of scheduled flow at the PJM/MISO interface border, but there would be no actual flows on the interface. Correspondingly, there would be no scheduled flows at the PJM/SOUTH interface border, but there would be 100 MW of actual flows on the interface. In the first three months of 2023, there were net scheduled flows of 426.8 GWh through MISO that received an interface pricing point associated with the southern interface but there were no net scheduled flows across the southern interface that received the MISO interface pricing point.

In the first three months of 2023, net scheduled interchange was -8,339.9 GWh and net actual interchange was -8,281.9 GWh, a difference of 58.0 GWh. In the first three months of 2022, net scheduled interchange was -9,458.6 GWh and net actual interchange was -9,434.1 GWh, a difference of 24.5 GWh. This difference is inadvertent interchange. PJM attempts to minimize the amount of accumulated inadvertent interchange by continually monitoring and correcting for inadvertent interchange. PJM can reduce the accumulation of inadvertent interchange using unilateral or bilateral paybacks. Inadvertent interchange accumulations that are paid back unilaterally are paid by controlling to a non-zero area control error (ACE). For example, Table 9-21 shows that PJM had 58.0 GW of inadvertent interchange in the first three months of 2023. To reduce this inadvertent interchange, PJM can control to an ACE greater than zero, which would result in over generating. By way of the power balance equation, power would flow out of PJM to its neighboring balancing authority areas. This would create additional actual exports that were not scheduled, thus reducing the overall inadvertent. To maintain reliability, unilateral paybacks are accounted for in the control performance standard calculations. Bilateral paybacks are scheduled with other balancing authority areas by scheduling a correction and incorporating that amount as a bias in the energy management system.[16]

15 See the *2012 State of the Market Report for PJM*, Volume II, Section 8, "Interchange Transactions," for a more detailed discussion.

16 See PJM. "Manual 12: Balancing Operations," Rev. 47 (October 1, 2022).

Table 9-21 shows that in the first three months of 2023, the Northern Indiana Public Service (NIPS) Interface had the largest loop flows of any interface with -0.2 GWh of net scheduled interchange and -3,276.9 GWh of net actual interchange, a difference of 3,276.8 GWh.

Table 9-21 Net scheduled and actual PJM flows by interface (GWh): January through March, 2023

Interface	Actual	Net Scheduled	Difference (GWh)
CPLE	718.4	(51.9)	770.2
CPLW	(10.8)	7.6	(18.4)
DUK	728.0	1,531.3	(803.4)
LGEE	934.1	(236.9)	1,171.0
MISO	(8,021.8)	(5,653.2)	(2,368.7)
ALTE	(607.9)	(784.8)	176.9
ALTW	(419.0)	(27.0)	(392.0)
AMIL	(658.9)	310.6	(969.5)
CIN	(980.3)	(1,985.4)	1,005.0
CWLP	(101.7)	0.0	(101.7)
IPL	(415.1)	(66.6)	(348.5)
MEC	(1,708.0)	(1,549.0)	(159.0)
MECS	(569.3)	(1,413.5)	844.2
NIPS	(3,276.9)	(0.2)	(3,276.8)
WEC	715.4	(137.2)	852.6
NYISO	(4,871.1)	(4,974.9)	103.8
HUDS	(1,071.5)	(1,071.5)	0.0
LIND	(628.9)	(628.9)	0.0
NEPT	(1,419.3)	(1,419.3)	0.0
NYIS	(1,751.4)	(1,855.2)	103.8
TVA	2,241.4	1,038.0	1,203.4
Total	(8,281.9)	(8,339.9)	58.0

Every external balancing authority is mapped to an import and export interface pricing point. The mapping is designed to reflect the physical flow of energy between PJM and each balancing authority. The net scheduled values for interface pricing points are defined as the MWh of scheduled transactions that will receive the interface pricing point based on the external balancing authority mapping.[17] For example, the MWh for a transaction whose transmission path is SPP through MISO and into PJM would be reflected in the SOUTH interface pricing point net schedule totals because SPP is mapped to the SOUTH interface pricing point. The actual flow on an interface pricing point is defined as the metered flow across the transmission lines that are included in the interface pricing point.

The differences between the scheduled MWh mapped to a specific interface pricing point and actual power flows at the interface pricing points provide a better measure of loop flows than differences at the interfaces. The scheduled transactions are mapped to interface pricing points based on the expected flow from the generation balancing authority and load balancing authority, whereas scheduled transactions are assigned to interfaces based solely on the OASIS path that the market participants reflect the transmission path into or out of PJM to one neighboring balancing authority. Power flows at the interface pricing points provide a more accurate reflection of where scheduled power flows actually enter or leave the PJM footprint based on the complete transaction path. Table 9-22 shows the net scheduled and actual PJM flows by interface pricing point.

The IMO interface pricing point with the Ontario IESO was created to reflect the fact that transactions that originate or sink in the Ontario Independent Electricity System Operator (IMO) balancing authority create physical flows that are split between the MISO and NYISO interface pricing points depending on transmission system conditions, so a mapping to a single interface pricing point does not reflect the actual flows. PJM created the IMO interface pricing point to reflect the actual power flows across both the MISO/PJM and NYISO/PJM Interfaces. The IMO does not have physical ties with PJM because it is not contiguous. Table 9-22 shows actual flows associated with the IMO interface pricing point as zero because there is no PJM/IMO Interface. The actual flows between IMO and PJM are included in the actual flows at the MISO and NYISO interface pricing points.

17 The terms balancing authority and control area are used interchangeably in this section. The NERC Tag applications maintained the terminology of generation control area (GCA) and load control area (LCA) after the implementation of the NERC functional model. The NERC functional model classifies the balancing authority as a reliability service function, with, among other things, the responsibility for balancing generation, demand and interchange balance.

Table 9-22 PJM flows by interface pricing point (GWh): January through March, 2023

Interface Pricing Point	Actual	Net Scheduled	Difference (GWh)
IMO	0.0	217.2	(217.2)
MISO	(8,021.8)	(6,298.3)	(1,723.5)
NYISO	(4,871.1)	(4,973.9)	102.7
HUDSONTP	(1,071.5)	(1,071.5)	0.0
LINDENVFT	(628.9)	(628.9)	0.0
NEPTUNE	(1,419.3)	(1,419.3)	0.0
NYIS	(1,751.4)	(1,854.2)	102.7
SOUTH	4,611.0	2,715.0	1,896.0
Total	(8,281.9)	(8,339.9)	58.0

Table 9-23 shows the net scheduled and actual PJM flows by interface pricing point, with adjustments made to the MISO and NYISO scheduled interface pricing points based on the quantities of scheduled interchange where transactions from the IMO entered the PJM energy market. For example, Table 9-25 shows that 218.5 of the 219.6 GWh (99.5 percent) of gross scheduled transactions that were mapped to the IMO interface pricing point were scheduled through MISO.

Table 9-23 shows that in the first three months of 2023, the MISO interface pricing point had the largest loop flows of any interface pricing point with 6,080.0 GWh of net scheduled interchange and 8,021.8 GWh of net actual interchange, a difference of 1,941.9 GWh.

Table 9-23 PJM flows by interface pricing point (GWh) (Adjusted for IMO Scheduled Interfaces): January through March, 2023

Interface Pricing Point	Actual	Net Scheduled	Difference (GWh)
MISO	(8,021.8)	(6,080.0)	(1,941.9)
NYISO	(4,871.1)	(4,974.9)	103.8
HUDSONTP	(1,071.5)	(1,071.5)	0.0
LINDENVFT	(628.9)	(628.9)	0.0
NEPTUNE	(1,419.3)	(1,419.3)	0.0
NYIS	(1,751.4)	(1,855.2)	103.8
SOUTH	4,611.0	2,715.0	1,896.0
Total	(8,281.9)	(8,339.9)	58.0

The NERC Tag requires the complete path to be specified from the generation control area (GCA) to the load control area (LCA), but participants do not always do so. The NERC Tag path is used by PJM to determine the interface pricing point that PJM assigns to the transaction. This approach will correctly identify the interface pricing point only if the market participant provides the complete path in the Tag. This approach will not correctly identify the interface pricing point if the market participant breaks the transaction into portions, each with a separate Tag. The breaking of transactions into portions can be a way to manipulate markets and the result of such behavior can be incorrect and noncompetitive pricing of transactions.

PJM attempts to ensure that external energy transactions are priced appropriately through the assignment of interface prices based on the expected actual flow from the generation balancing authority (source) and load balancing authority (sink) as specified on the NERC Tag. Assigning prices in this manner is a reasonable approach to ensuring that transactions receive or pay the PJM market value of the transaction based on expected flows, but this method does not address loop flow issues.

Loop flows remain a significant concern for the efficiency of the PJM market. Loop flows can have negative impacts on the efficiency of markets with explicit locational pricing, including impacts on locational prices, on FTR revenue adequacy and on system operations, and can be evidence of attempts to game the markets.

The MMU recommends that PJM implement a validation method for submitted transactions that would prohibit market participants from breaking transactions into smaller segments to defeat the interface pricing rule and receive higher prices (for imports) or lower prices (for exports) from PJM resulting from the inability to identify the true source or sink of the transaction. If all of the Northeast ISOs and RTOs implemented validation to prohibit the breaking of transactions into smaller segments, the level of Lake Erie loop flow would be reduced.

The MMU also recommends that PJM implement a validation method for submitted transactions that would require market participants to submit transactions on paths that reflect the expected actual power flow in order to reduce unscheduled loop flows.

Table 9-24 shows the net scheduled and actual PJM flows by interface and interface pricing point. This table shows the interface pricing points that were assigned to energy transactions that had paths at each of PJM's interfaces. For example, Table 9-24 shows that in the first three months of 2023, the majority of imports to the PJM energy market for which a market participant specified Ameren-Illinois (AMIL) as the interface with PJM based on the scheduled transmission path, had a generation control area mapped to the SOUTH Interface, and thus actual flows were assigned the SOUTH interface pricing point (329.8 GWh). The majority of exports from the PJM energy market for which a market participant specified AMIL as the interface with PJM based on the scheduled transmission path had a load control area for which the actual flows would leave the PJM energy market at the MISO Interface, and were assigned the MISO interface pricing point (-34.5 GWh).

Table 9-24 Net scheduled and actual flows by interface and interface pricing point (GWh): January through March, 2023

Interface	Interface Pricing Point	Actual	Net Scheduled	Difference (GWh)	Interface	Interface Pricing Point	Actual	Net Scheduled	Difference (GWh)
ALTE		(607.9)	(784.8)	176.9	LGEE		934.1	(236.9)	1,171.0
	IMO	0.0	13.4	(13.4)		SOUTH	934.1	(236.9)	1,171.0
	MISO	(607.9)	(796.5)	188.6	LIND		(628.9)	(628.9)	0.0
	SOUTH	0.0	(1.7)	1.7		LINDENVFT	(628.9)	(628.9)	0.0
ALTW		(419.0)	(27.0)	(392.0)	MEC		(1,708.0)	(1,549.0)	(159.0)
	MISO	(419.0)	(26.8)	(392.2)		IMO	0.0	(0.1)	0.1
	SOUTH	0.0	(0.2)	0.2		MISO	(1,708.0)	(1,548.9)	(159.1)
AMIL		(658.9)	310.6	(969.5)	MECS		(569.3)	(1,413.5)	844.2
	IMO	0.0	15.3	(15.3)		IMO	0.0	178.9	(178.9)
	MISO	(658.9)	(34.5)	(624.4)		MISO	(569.3)	(1,599.9)	1,030.6
	SOUTH	0.0	329.8	(329.8)		SOUTH	0.0	7.4	(7.4)
CIN		(980.3)	(1,985.4)	1,005.0	NEPT		(1,419.3)	(1,419.3)	0.0
	IMO	0.0	3.0	(3.0)		NEPTUNE	(1,419.3)	(1,419.3)	0.0
	MISO	(980.3)	(1,981.0)	1,000.6	NIPS		(3,276.9)	(0.2)	(3,276.8)
	SOUTH	0.0	(7.4)	7.4		MISO	(3,276.9)	(0.2)	(3,276.8)
CPLE		718.4	(51.9)	770.2	NYIS		(1,751.4)	(1,855.2)	103.8
	SOUTH	718.4	(51.9)	770.2		IMO	0.0	(1.1)	1.1
CPLW		(10.8)	7.6	(18.4)		NYIS	(1,751.4)	(1,854.2)	102.7
	SOUTH	(10.8)	7.6	(18.4)	TVA		2,241.4	1,038.0	1,203.4
CWLP		(101.7)	0.0	(101.7)		SOUTH	2,241.4	1,038.0	1,203.4
	MISO	(101.7)	0.0	(101.7)	WEC		715.4	(137.2)	852.6
DUK		728.0	1,531.3	(803.4)		MISO	715.4	(236.1)	951.4
	SOUTH	728.0	1,531.3	(803.4)		SOUTH	0.0	98.9	(98.9)
HUDS		(1,071.5)	(1,071.5)	0.0	Grand Total		(8,281.9)	(8,339.9)	58.0
	HUDSONTP	(1,071.5)	(1,071.5)	0.0					
IPL		(415.1)	(66.6)	(348.5)					
	IMO	0.0	7.8	(7.8)					
	MISO	(415.1)	(74.4)	(340.7)					

Table 9-25 shows the net scheduled and actual PJM flows by interface pricing point and interface. The grouping is reversed from Table 9-24. Table 9-25 shows the interfaces where transactions were scheduled which received the individual interface pricing points. For example, Table 9-25 shows that in the first three months of 2023, the majority of imports to the PJM energy market for which a market participant specified a generation control area for which it was assigned the SOUTH interface pricing point, had a path that entered the PJM energy market at the DUK Interface (1,531.3 GWh). The majority of exports from the PJM energy market for which a market participant specified a load control area for which it was assigned the SOUTH interface pricing point, had a path that would leave the PJM energy market at the LGEE Interface (-236.9 GWh).

Table 9-25 Net scheduled and actual flows by interface pricing point and interface (GWh): January through March, 2023

Interface Pricing Point	Interface	Actual	Net Scheduled	Difference (GWh)	Interface Pricing Point	Interface	Actual	Net Scheduled	Difference (GWh)
HUDSONTP		(1,071.5)	(1,071.5)	0.0	NEPTUNE		(1,419.3)	(1,419.3)	0.0
	HUDS	(1,071.5)	(1,071.5)	0.0		NEPT	(1,419.3)	(1,419.3)	0.0
IMO		0.0	217.2	(217.2)	NYIS		(1,751.4)	(1,854.2)	102.7
	ALTE	0.0	13.4	(13.4)		NYIS	(1,751.4)	(1,854.2)	102.7
	AMIL	0.0	15.3	(15.3)	SOUTH		4,611.0	2,715.0	1,896.0
	CIN	0.0	3.0	(3.0)		ALTE	0.0	(1.7)	1.7
	IPL	0.0	7.8	(7.8)		ALTW	0.0	(0.2)	0.2
	MEC	0.0	(0.1)	0.1		AMIL	0.0	329.8	(329.8)
	MECS	0.0	178.9	(178.9)		CIN	0.0	(7.4)	7.4
	NYIS	0.0	(1.1)	1.1		CPLE	718.4	(51.9)	770.2
LINDENVFT		(628.9)	(628.9)	0.0		CPLW	(10.8)	7.6	(18.4)
	LIND	(628.9)	(628.9)	0.0		DUK	728.0	1,531.3	(803.4)
MISO		(8,021.8)	(6,298.3)	(1,723.5)		LGEE	934.1	(236.9)	1,171.0
	ALTE	(607.9)	(796.5)	188.6		MECS	0.0	7.4	(7.4)
	ALTW	(419.0)	(26.8)	(392.2)		TVA	2,241.4	1,038.0	1,203.4
	AMIL	(658.9)	(34.5)	(624.4)		WEC	0.0	98.9	(98.9)
	CIN	(980.3)	(1,981.0)	1,000.6	Grand Total		(8,281.9)	(8,339.9)	58.0
	CWLP	(101.7)	0.0	(101.7)					
	IPL	(415.1)	(74.4)	(340.7)					
	MEC	(1,708.0)	(1,548.9)	(159.1)					
	MECS	(569.3)	(1,599.9)	1,030.6					
	NIPS	(3,276.9)	(0.2)	(3,276.8)					
	WEC	715.4	(236.1)	951.4					

Data Required for Full Loop Flow Analysis

Loop flows are defined as the difference between actual and scheduled power flows at one or more specific interfaces. The differences between actual and scheduled power flows can be the result of a number of underlying causes. To adequately investigate the causes of loop flows, complete data are required.

Loop flows exist because electricity flows on the path of least resistance regardless of the path specified by contractual agreement or regulatory prescription. Loop flows can arise from transactions scheduled into, out of or around a balancing authority on contract paths that do not correspond to the actual physical paths on which energy flows. Outside of LMP-based energy markets, energy is scheduled and paid for based on contract path, without regard to the path of the actual energy flows. Loop flows can also result from actions within balancing authorities.

Loop flows are a significant concern. Loop flows can have negative impacts on the efficiency of markets with explicit locational pricing, including impacts on locational prices, on FTR revenue adequacy and on system operations, and can be evidence of attempts to game such markets. Loop flows also have poorly understood impacts on nonmarket areas. In general, the detailed sources of the identified differences between scheduled and actual flows remain unclear as a result of incomplete or inadequate access to the required data.

A complete analysis of loop flow could provide additional insight that could lead to enhanced overall market efficiency and clarify the interactions among market and nonmarket areas. A complete analysis of loop flow would improve the overall transparency of electricity transactions. There are areas with transparent markets, and there are areas with less transparent markets (nonmarket areas), but these areas together comprise a market, and overall market efficiency would benefit from the increased transparency that would derive from a better understanding of loop flows.

For a complete loop flow analysis, several types of data are required from all balancing authorities in the Eastern Interconnection. The Commission required access to NERC Tag data. In addition to the Tag data, actual tie line data, dynamic schedule and pseudo tie data are required in order to analyze the differences between actual and scheduled transactions. ACE data, market flow impact data and generation and load data are required in order to understand the sources, within each balancing authority, of loop flows that do not result from differences between actual and scheduled transactions.[18]

NERC Tag Data

An analysis of loop flow requires knowledge of the scheduled path of energy transactions. NERC Tag data include the scheduled path and energy profile of the transactions, including the Generation Control Area (GCA), the intermediate Control Areas, the Load Control Area (LCA) and the energy profile of all transactions. Complete tag data include the identity of the specific market participants. FERC Order No. 771 required access to NERC Tag data for the Commission, regional transmission organizations, independent system operators and market monitoring units.[19]

Actual Tie Line Flow Data

An analysis of loop flow requires knowledge of the actual path of energy transactions. Currently, a very limited set of tie line data is made available via the NERC IDC and the Central Repository for Curtailments (CRC) website. The available tie line data, and the data within the IDC, are presented as information on a screen, which does not permit analysis of the underlying data.

Dynamic Schedule and Pseudo Tie Data

Dynamic schedule and pseudo ties represent another type of interchange transaction between balancing authorities. While dynamic schedules are required to be tagged, the tagged profile is only an estimate of what energy is expected to flow. Dynamic schedules are implemented within each balancing authority's Energy Management System (EMS), with the current values shared over Inter-Control Center Protocol (ICCP) links. By definition, the dynamic schedule scheduled and actual values will always be identical from a balancing authority standpoint, and the tagged profile should be removed from the calculation of loop flows to eliminate double counting of the energy profile. Dynamic schedule data from all balancing authorities are required in order to account for all scheduled and actual flows.

Pseudo ties are similar to dynamic schedules in that they represent a transaction between balancing authorities and are handled within the EMS systems and data are shared over the ICCP. Pseudo ties differ from dynamic schedules in how the generating resource is modeled within the balancing authorities' ACE equations. Dynamic schedules are modeled as resources located in one area serving load in another, while pseudo ties are modeled as resources in one area moved to another area. Unlike dynamic schedules, pseudo tie transactions are not required to be tagged. Pseudo tie data from all balancing authorities are required in order to account for all scheduled and actual flows.

18 It is requested that all data be made available in downloadable format in order to make analysis possible. A data viewing tool alone is not adequate.

19 141 FERC ¶ 61,235 (2012).

Area Control Error (ACE) Data

Area control error (ACE) data provides information about how well each balancing authority is matching their generation with their load. This information, combined with the scheduled and actual interchange values will show whether an individual balancing authority is pushing on or leaning on the interconnection, contributing to loop flows.

NERC makes real-time ACE graphs available on their Reliability Coordinator Information System (RCIS) website. This information is presented only in graphical form, and the underlying data is not available for analysis.

Market Flow Impact Data

In addition to interchange transactions, internal dispatch can also affect flows on balancing authorities' tie lines. The impact of internal dispatch on tie lines is called market flow. Market flow data are imported in the IDC, but there is only limited historical data, as only market flow data related to TLR levels 3 or higher are required to be made available via a Congestion Management Report (CMR). The remaining data are deleted.

There is currently a project in development through the NERC Operating Reliability Subcommittee (ORS) called the Market Flow Impact Tool. The purpose of this tool is to make visible the impacts of dispatch on loop flows. The MMU supports the development of this tool, but, equally important, requests that FERC and NERC ensure that the underlying data are provided to market monitors and other approved entities.

Generation and Load Data

Generation data (both real-time scheduled generation and actual output) and load data would permit analysis of the extent to which balancing authorities are meeting their commitments to serve load. If a balancing authority is not meeting its load commitment with adequate generation, the result is unscheduled flows across the interconnections to establish power balance.

Market areas are transparent in providing real-time load while nonmarket areas are not. For example, PJM posts real-time load via its eDATA application. Most nonmarket balancing authorities provide only the expected peak load on their individual websites. Data on generation are not made publicly available, as this is considered market sensitive information.

The MMU recommends, that in order to permit a complete analysis of loop flow, FERC and NERC ensure that the identified data are made available to market monitors as well as other industry entities determined appropriate by FERC.

PJM and MISO Interface Prices

Both the PJM/MISO and MISO/PJM interface pricing points represent the value of power at the relevant border, as determined in each market. In both cases, the interface price is the price at which transactions are settled. For example, a transaction into PJM from MISO would receive the PJM/MISO interface price upon entering PJM, while a transaction into MISO from PJM would receive the MISO/PJM interface price. PJM and MISO use network models to determine these prices and to attempt to ensure that the prices are consistent with the underlying electrical flows.

Under the PJM/MISO Joint Operating Agreement, the two RTOs mutually determine a set of transmission facilities on which both RTOs have an impact, and therefore jointly operate to those constraints. These jointly controlled facilities are M2M (Market to Market) flowgates. When a M2M constraint binds, PJM's LMP calculations at the buses that make up PJM's MISO interface pricing point are based on the PJM model's distribution factors of the selected buses to the binding M2M constraint and PJM's shadow price of the binding M2M constraint. MISO's LMP calculations at the buses that make up MISO's PJM interface pricing point are based on the MISO model's distribution factors of the selected buses to the binding M2M constraint and MISO's shadow price of the binding M2M constraint.

Prior to June 1, 2014, the PJM interface definition for MISO consisted of nine buses located near the middle of the MISO system and not at the border between the RTOs.[20] The interface definitions led to questions about the level of congestion included in interchange pricing.

PJM modified the definition of the PJM/MISO interface price effective June 1, 2014. PJM's new MISO interface pricing point includes 10 equally weighted buses that are close to the PJM/MISO border. The 10 buses were selected based on PJM's analysis that showed that over 80 percent of the hourly tie line flows between PJM and MISO occurred on 10 ties composed of MISO and PJM monitored facilities. On June 1, 2017, MISO modified their MISO/PJM interface definition to match PJM's PJM/MISO interface definition.

Real-Time and Day-Ahead PJM/MISO Interface Prices

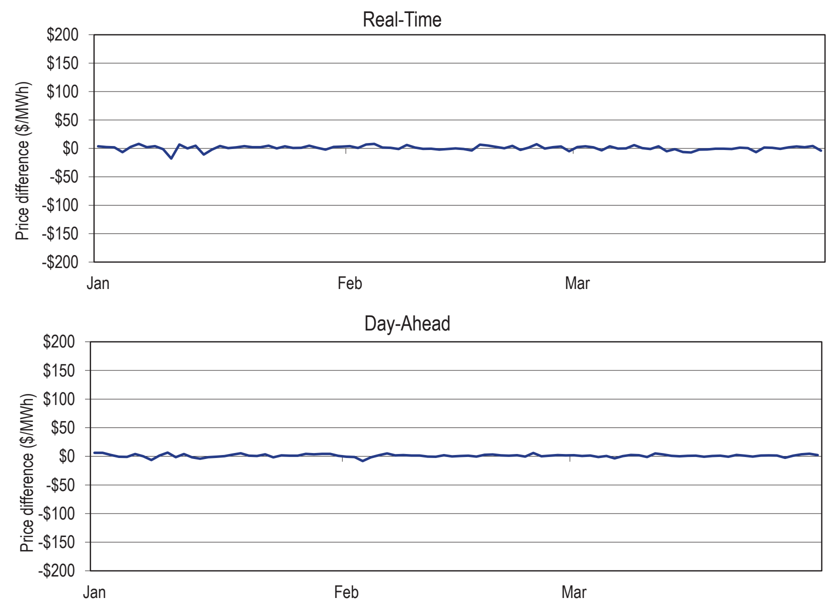
In the first three months of 2023, the direction of flow was consistent with price differentials in 59.8 percent of the hours. Table 9-26 shows the number of hours and average hourly price differences between the PJM/MISO Interface and the MISO/PJM Interface based on LMP differences and flow direction. Table 9-26 shows that PJM was a net exporter of energy to MISO in all but one hour during the first three months of 2023. The lack of response to relative prices on the PJM/MISO interface was consistent with the ongoing pattern that there are net exports from PJM to MISO in almost every hour, regardless of relative prices. In the first three months of 2023, flows were in the uneconomic direction on the PJM/MISO interface in 40.2 percent of all hours. Figure 9-5 shows the underlying variability in prices calculated on a daily hourly average basis. There are a number of relevant measures of variability, including the number of times the price differential fluctuates between positive and negative, the standard deviation of individual prices and of price differences and the absolute value of the price differences (Table 9-30).

20 See "LMP Aggregate Definitions," (March 15, 2023) <http://www.pjm.com/~/media/markets-ops/energy/lmp-model-info/lmp-aggregate-definitions.ashx>. PJM periodically updates these definitions on its website. See <http://www.pjm.com>.

Table 9-26 PJM and MISO flow based hours and price differences: January through March, 2023

LMP Difference	Flow Direction	Number of Hours	Average Hourly Price Difference
MISO/PJM LMP > PJM/MISO LMP	Total Hours	1,292	$5.97
	Consistent Flow (PJM to MISO)	1,291	$5.97
	Inconsistent Flow (MISO to PJM)	1	$1.34
	No Flow	0	$0.00
PJM/MISO LMP > MISO/PJM LMP	Total Hours	867	$6.92
	Consistent Flow (MISO to PJM)	0	$0.00
	Inconsistent Flow (PJM to MISO)	867	$6.92
	No Flow	0	$0.00

Figure 9-5 Price differences (MISO/PJM Interface minus PJM/MISO Interface): January through March, 2023



Distribution and Prices of Hourly Flows at the PJM/MISO Interface

Almost without exception, power flows from PJM to MISO regardless of the direction of price differences. In the first three months of 2023, the direction of hourly energy flows was consistent with PJM and MISO interface price differentials in 1,291 hours (59.8 percent of all hours), and was inconsistent with price differentials in 868 hours (40.2 percent of all hours). Table 9-27 shows the distribution of hourly energy flows between PJM and MISO based on the price differences between the PJM/MISO and MISO/PJM prices. Of the 868 hours where flows were in a direction inconsistent with price differences, 707 of those hours (81.5 percent) had a price difference greater than or equal to $1.00 and 298 of those hours (34.3 percent) had a price difference greater than or equal to $5.00. The largest price difference with such flows was $406.49. Of the 1,291 hours where flows were consistent with price differences, 1,093 of those hours (84.7 percent) had a price difference greater than or equal to $1.00 and 364 of all such hours (28.2 percent) had a price difference greater than or equal to $5.00. The largest price difference with such flows was $318.46.

Table 9-27 Distribution of hourly flows that are consistent and inconsistent with price differences between PJM and MISO: January through March, 2023

Price Difference Range (Greater Than or Equal To)	Inconsistent Hours	Percent of Inconsistent Hours	Consistent Hours	Percent of Consistent Hours
$0.00	868	100.0%	1,291	100.0%
$1.00	707	81.5%	1,093	84.7%
$5.00	298	34.3%	364	28.2%
$10.00	147	16.9%	122	9.5%
$15.00	95	10.9%	72	5.6%
$20.00	63	7.3%	49	3.8%
$25.00	42	4.8%	46	3.6%
$50.00	13	1.5%	22	1.7%
$75.00	5	0.6%	10	0.8%
$100.00	1	0.1%	5	0.4%
$200.00	1	0.1%	3	0.2%
$300.00	1	0.1%	1	0.1%
$400.00	1	0.1%	0	0.0%
$500.00	0	0.0%	0	0.0%

PJM and NYISO Interface Prices

If interface prices were defined in a comparable manner by PJM and the NYISO, if identical rules governed external transactions in PJM and the NYISO, if time lags were not built into the rules governing such transactions and if no risks were associated with such transactions, then prices at the interfaces would be expected to be very close and the level of transactions would be expected to be related to any price differentials. The fact that none of these conditions exists is important in explaining the observed relationship between interface prices and inter-RTO/ISO power flows, and those price differentials.[21]

PJM and NYISO each calculate an interface LMP using network models including distribution factor impacts. Prior to May 1, 2017, PJM used two buses within NYISO to calculate the PJM/NYIS interface pricing point LMP. The NYISO uses proxy buses to calculate interface prices with neighboring balancing authorities. A proxy bus is a single bus, located outside the NYISO footprint, which represents generation and load in a neighboring balancing authority area. The NYISO models imports from PJM as generation at the Keystone proxy bus, delivered to the NYISO reference bus with the assumption that 32 percent of the flow will enter the NYISO across the free flowing A/C ties, 32 percent will enter the NYISO across the Ramapo PARs, 21 percent will enter the NYISO across the ABC PARs and 15 percent will enter the NYISO across the J/K PARs. The NYISO models exports to PJM as being delivered to load at the Keystone proxy bus, sourced from the NYISO reference bus with the assumption that 32 percent of the flow will enter PJM across the free flowing A/C ties, 32 percent will enter PJM across the Ramapo PARs, 21 percent will enter PJM across the ABC PARs and 15 percent will enter PJM across the J/K PARs.

The PJM/NYIS interface definition using two buses was created to include the impact of the ConEd wheeling agreement. The ConEd wheeling agreement ended on May 1, 2017. The end of the wheeling agreement meant that the expected actual power flows would change and therefore the definition of the interface price needed to change. Effective May 1, 2017, PJM replaced the old PJM/NYIS interface price definition. The new PJM/NYIS interface

21 See the *2012 State of the Market Report for PJM*, Volume II, Section 8, "Interchange Transactions," for a more detailed discussion.

price is based on four buses within NYISO. The four buses were chosen based on a power flow analysis of transfers between PJM and the NYISO and the resultant distribution of flows across the free flowing A/C ties.

Real-Time and Day-Ahead PJM/NYISO Interface Prices

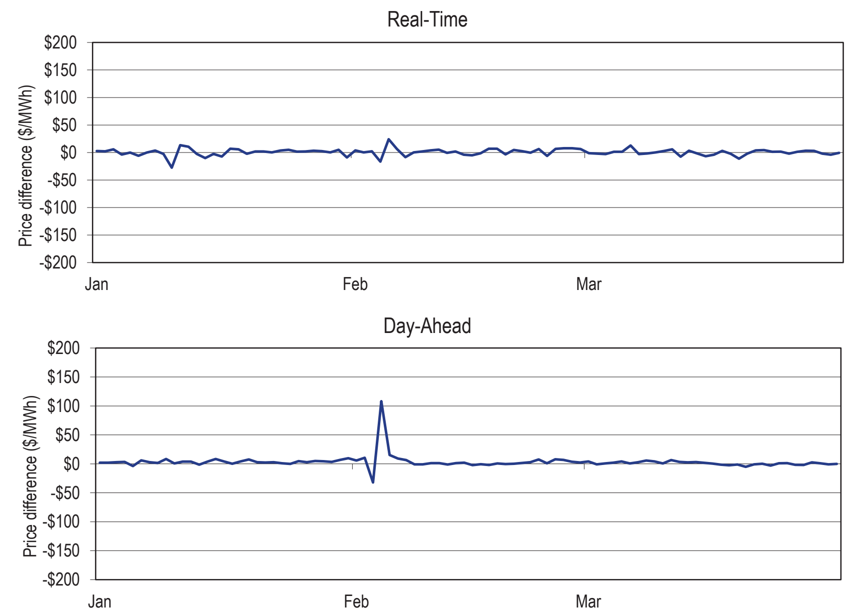
In the first three months of 2023, the relationship between prices at the PJM/NYIS Interface and at the NYISO/PJM proxy bus and the relationship between interface price differentials and power flows continued to be affected by differences in institutional and operating practices between PJM and the NYISO. The direction of flow was consistent with price differentials in 57.9 percent of the hours in the first three months of 2023. Table 9-28 shows the number of hours and average hourly price differences between the PJM/NYIS Interface and the NYIS/PJM proxy bus based on LMP differences and flow direction. Figure 9-6 shows the underlying variability in prices calculated on a daily hourly average basis. There are a number of relevant measures of variability, including the number of times the price differential fluctuates between positive and negative, the standard deviation of individual prices and of price differences and the absolute value of the price differences (Table 9-30).

Table 9-28 PJM and NYISO flow based hours and price differences: January through March, 2023[22]

LMP Difference	Flow Direction	Number of Hours	Average Hourly Price Difference
	Total Hours	1,239	$8.14
NYIS/PJM proxy bus LBMP > PJM/NYIS LMP	Consistent Flow (PJM to NYIS)	1,115	$8.24
	Inconsistent Flow (NYIS to PJM)	124	$7.21
	No Flow	0	$0.00
	Total Hours	920	$9.25
PJM/NYIS LMP > NYIS/PJM proxy bus LBMP	Consistent Flow (NYIS to PJM)	134	$5.98
	Inconsistent Flow (PJM to NYIS)	786	$9.81
	No Flow	0	$0.00

22 The NYISO Locational Based Marginal Price (LBMP) is the equivalent term to PJM's Locational Marginal Price (LMP).

Figure 9-6 Price differences (NY/PJM proxy - PJM/NYIS Interface): January through March, 2023



Distribution and Prices of Hourly Flows at the PJM/NYISO Interface

In the first three months of 2023, the direction of hourly energy flows was consistent with PJM/NYISO and NYISO/PJM price differences in 1,249 hours (57.9 percent of all hours), and was inconsistent with price differences in 910 hours (42.1 percent of all hours). Table 9-29 shows the distribution of hourly energy flows between PJM and NYISO based on the price differences between the PJM/NYISO and NYISO/PJM prices. Of the 910 hours where flows were in a direction inconsistent with price differences, 793 of those hours (87.1 percent) had a price difference greater than or equal to $1.00 and 403 of all those hours (44.3 percent) had a price difference greater than or equal to $5.00. The largest price difference with such flows was $514.41. Of the 1,249 hours where flows were consistent with price differences, 1,088 of those hours

(87.1 percent) had a price difference greater than or equal to $1.00 and 512 of all such hours (41.0 percent) had a price difference greater than or equal to $5.00. The largest price difference with such flows was $222.87.

Table 9-29 Distribution of hourly flows that are consistent and inconsistent with price differences between PJM and NYISO: January through March, 2023

Price Difference Range (Greater Than or Equal To)	Inconsistent Hours	Percent of Inconsistent Hours	Consistent Hours	Percent of Consistent Hours
$0.00	910	100.0%	1,249	100.0%
$1.00	793	87.1%	1,088	87.1%
$5.00	403	44.3%	512	41.0%
$10.00	199	21.9%	226	18.1%
$15.00	120	13.2%	134	10.7%
$20.00	95	10.4%	84	6.7%
$25.00	69	7.6%	64	5.1%
$50.00	26	2.9%	25	2.0%
$75.00	10	1.1%	11	0.9%
$100.00	7	0.8%	7	0.6%
$200.00	1	0.1%	2	0.2%
$300.00	1	0.1%	0	0.0%
$400.00	1	0.1%	0	0.0%
$500.00	1	0.1%	0	0.0%

Summary of Interface Prices between PJM and Organized Markets

Some measures of the real-time and day-ahead PJM interface pricing with MISO and with the NYISO are summarized and compared in Table 9-30, including average prices and measures of variability.

Table 9-30 PJM, NYISO and MISO border price averages: January through March, 2023[23]

		Real-Time		Day-Ahead	
	Description	NYISO	MISO	NYISO	MISO
Average Interval Price	PJM Price at ISO Border	$28.32	$27.28	$30.20	$28.37
	ISO Price at PJM Border	$28.98	$28.08	$33.41	$29.50
	Difference at Border (PJM-ISO)	($0.66)	($0.79)	($3.22)	($1.13)
	Average Absolute Value of Interval Difference at Border	$48.93	$37.42	$12.91	$3.09
	Sign Changes per Day	12.0	14.0	0.7	0.9
Standard Deviation	PJM Price at ISO Border	$34.52	$29.87	$15.40	$8.52
	ISO Price at PJM Border	$38.48	$26.56	$20.38	$7.34
	Difference at Border (PJM-ISO)	$50.13	$38.29	$13.64	$4.39

23 Effective April 1, 2018, PJM implemented 5 minute LMP settlements in the real-time energy market. The sign changes per day represented in this table reflect the number of intervals where the sign changed per day. For the real-time energy market, there are 288 five minute intervals. For the day-ahead market there are 24 hourly intervals.

Neptune Underwater Transmission Line to Long Island, New York

The Neptune Line is a 65 mile direct current (DC) merchant 230 kV transmission line, with a capacity of 660 MW, providing a direct connection between PJM (Sayreville, New Jersey), and NYISO (Nassau County on Long Island). Schedule 14 of the PJM Open Access Transmission Tariff provides that power flows will only be from PJM to New York. The flows were consistent with price differentials in 87.6 percent of the hours in the first three months of 2023. Table 9-31 shows the number of hours and average hourly price differences between the PJM/NEPT Interface and the NYIS/Neptune bus based on LMP differences and flow direction.

Table 9-31 PJM and NYISO flow based hours and price differences (Neptune): January through March, 2023

LMP Difference	Flow Direction	Number of Hours	Average Hourly Price Difference
NYIS/Neptune Bus LBMP > PJM/NEPT LMP	Total Hours	1,892	$23.86
	Consistent Flow (PJM to NYIS)	1,892	$23.86
	Inconsistent Flow (NYIS to PJM)	0	$0.00
	No Flow	0	$0.00
PJM/NEPT LMP > NYIS/Neptune Bus LBMP	Total Hours	267	$9.82
	Consistent Flow (NYIS to PJM)	0	$0.00
	Inconsistent Flow (PJM to NYIS)	267	$9.82
	No Flow	0	$0.00

To move power from PJM to NYISO using the Neptune Line, two PJM transmission service reservations are required. A transmission service reservation is required from the PJM Transmission System to the Neptune HVDC Line ("Out Service") and another transmission service reservation is required on the Neptune HVDC Line ("Neptune Service").[24] The PJM Out Service is covered by normal PJM OASIS business operations.[25] The Neptune Service falls under the provisions for controllable merchant facilities, Schedule 14 of the PJM Tariff. The Neptune Service is also acquired on the PJM OASIS.

Neptune Service is owned by a primary rights holder, and any nonfirm service that is not used (as defined by a schedule on a NERC Tag) may be released either voluntarily by the primary rights holder or by default by PJM. The primary rights holder may elect to voluntarily release monthly, weekly, daily or hourly firm or nonfirm service. Voluntarily releasing the service allows for the primary rights holder to specify a rate to be charged for the released service. If the primary rights holder does not elect to voluntarily release nonfirm service, and does not use the service, the available transmission will be released by default at 12:00, one business day before the start of service. On March 31, 2023, the rate for the nonfirm service released by default was $10.00 per MWh. The primary rights holder remains obligated to pay for the released service unless a second transmission customer acquires the released service.

Table 9-32 shows the percent of scheduled interchange across the Neptune Line by the primary rights holder since commercial operations began in July 2007. Table 9-32 shows that in the first three months of 2023, the primary rights holder was responsible for 100 percent of the scheduled interchange across the Neptune Line in all months. Figure 9-7 shows the hourly average flow across the Neptune Line for the first three months of 2023.

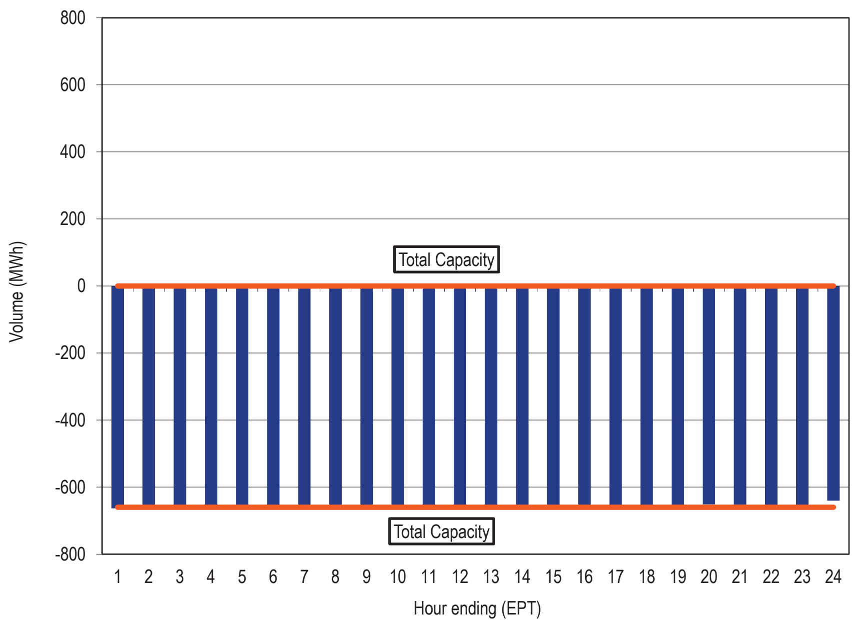
24 See OASIS "PJM Business Practices for Neptune Transmission Service," (August 21, 2015) <http://www.pjm.com/~/media/etools/oasis/merch-trans-facilities/neptune-oasis-Business-practices-doc-clean.ashx>.

25 See OASIS "Regional Transmission and Energy Scheduling Practices," Rev. 11 (January 27, 2023) <http://www.pjm.com/~/media/etools/oasis/regional-practices-clean-pdf.ashx>.

Table 9-32 Percent of scheduled interchange across the Neptune Line by primary rights holder: July 2007 through March 2023

	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
January	NA	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
February	NA	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
March	NA	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
April	NA	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	99.99%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	
May	NA	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	
June	NA	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	
July	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	
August	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	
September	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	
October	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	
November	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	
December	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	

Figure 9-7 Neptune hourly average flow: January through March, 2023



Linden Variable Frequency Transformer (VFT) facility

The Linden VFT facility is a controllable AC merchant transmission facility, with a capacity of 315 MW, providing a direct connection between PJM (Linden, New Jersey) and NYISO (Staten Island, New York). The flows were consistent with price differentials in 82.9 percent of the hours in the first three months of 2023. Table 9-33 shows the number of hours and average hourly price differences between the PJM/LIND Interface and the NYIS/Linden Bus based on LMP differences and flow direction.

Table 9-33 PJM and NYISO flow based hours and price differences (Linden): January through March, 2023

LMP Difference	Flow Direction	Number of Hours	Average Hourly Price Difference
NYIS/Linden Bus LBMP > PJM/LIND LMP	Total Hours	1,790	$16.00
	Consistent Flow (PJM to NYIS)	1,790	$16.00
	Inconsistent Flow (NYIS to PJM)	0	$0.00
	No Flow	0	$0.00
PJM/LIND LMP > NYIS/Linden Bus LBMP	Total Hours	369	$12.21
	Consistent Flow (NYIS to PJM)	0	$0.00
	Inconsistent Flow (PJM to NYIS)	369	$12.21
	No Flow	0	$0.00

To move power from PJM to NYISO on the Linden VFT Line, two PJM transmission service reservations are required. A transmission service reservation is required from the PJM Transmission System to the Linden VFT (“Out Service”) and another transmission service reservation is required on the Linden VFT (“Linden VFT Service”).[26] The PJM Out Service is covered by normal PJM OASIS business operations.[27] The Linden VFT Service falls under the provisions for controllable merchant facilities, Schedule 16 and Schedule 16-A of the PJM Tariff. The Linden VFT Service is also acquired on the PJM OASIS.

Linden VFT Service is owned by a primary rights holder, and any nonfirm service that is not used (as defined by a schedule on a NERC Tag) may be released either voluntarily by the primary rights holder or by default by PJM. The primary rights holder may elect to voluntarily release monthly, weekly, daily or hourly firm or nonfirm service. Voluntarily releasing the service allows for the primary rights holder to specify a rate to be charged for the released service. If the primary rights holder elects to not voluntarily release nonfirm service, and does not use the service, the available transmission will be released by default at 1200 (EPT), one business day before the start of service. On March 31, 2023, the rate for the nonfirm service released by default was $6.00 per MWh. The primary rights holder remains obligated to pay for the released service unless a second transmission customer acquires the released service.

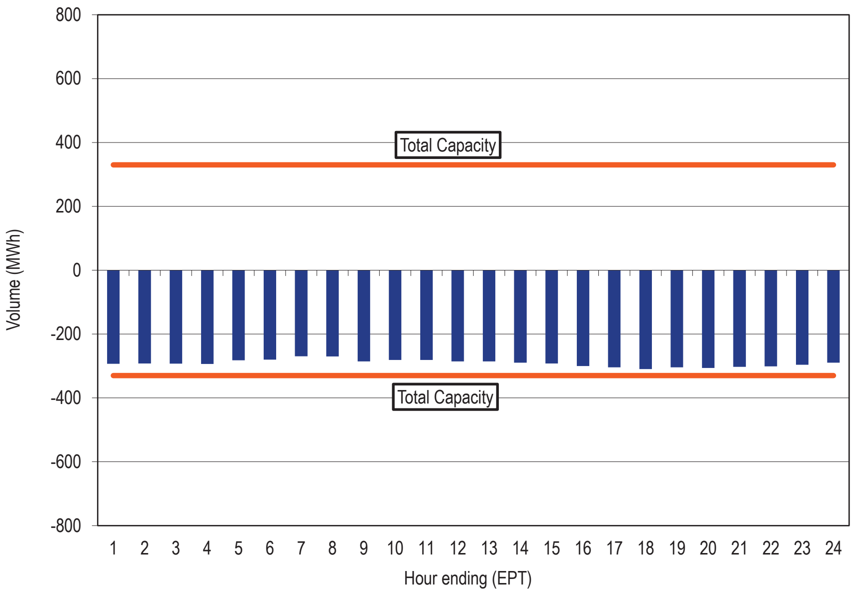
Table 9-34 shows the percent of scheduled interchange across the Linden VFT Line by the primary rights holder since commercial operations began in November, 2009. Table 9-34 shows that in the first three months of 2023, the primary rights holder was responsible for 100 percent of the scheduled interchange across the Linden VFT Line in all months. Figure 9-8 shows the hourly average flow across the Linden VFT Line for the first three months of 2023.

Table 9-34 Percent of scheduled interchange across the Linden VFT Line by primary rights holder: November 2009 through March 2023

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
January	NA	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	70.53%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
February	NA	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	94.95%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
March	NA	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	96.46%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
April	NA	99.97%	100.00%	100.00%	100.00%	99.98%	100.00%	49.32%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	
May	NA	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	
June	NA	100.00%	100.00%	100.00%	100.00%	27.27%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	
July	NA	100.00%	100.00%	100.00%	100.00%	29.56%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	
August	NA	100.00%	100.00%	100.00%	100.00%	82.46%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	
September	NA	100.00%	100.00%	100.00%	100.00%	81.68%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	
October	NA	100.00%	100.00%	100.00%	100.00%	100.00%	35.05%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	
November	100.00%	100.00%	100.00%	100.00%	99.86%	100.00%	61.45%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	
December	100.00%	100.00%	100.00%	98.22%	100.00%	100.00%	84.57%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	

26 See OASIS "PJM Business Practices for Linden VFT Transmission Service," (June 1, 2011) <http://www.pjm.com/~/media/etools/oasis/merch-trans-facilities/linden-vft-oasis-Business-practices-doc-clean.ashx>.
27 See OASIS "Regional Transmission and Energy Scheduling Practices," Rev. 11 (January 27, 2023) <https://www.pjm.com/-/media/etools/oasis/regional-practices-clean-pdf.ashx>.

Figure 9-8 Linden hourly average flow: January through March, 2023[28]



Hudson Direct Current (DC) Merchant Transmission Line

The Hudson direct current (DC) Line is a bidirectional merchant 230 kV transmission line, with a capacity of 673 MW, providing a direct connection between PJM (Public Service Electric and Gas Company's (PSE&G) Bergen 230 kV Switching Station located in Ridgefield, New Jersey) and NYISO (Consolidated Edison's (Con Ed) W. 49th Street 345 kV Substation in New York City). The connection is a submarine cable system. While the Hudson DC Line is a bidirectional line, power flows are only from PJM to New York because the Hudson Transmission Partners, LLC had only requested withdrawal rights (320 MW of firm withdrawal rights, and 353 MW of nonfirm withdrawal rights). The flows were consistent with price differentials in 75.2 percent of the hours in the first three months of 2023. Table 9-35 shows the number of hours and average hourly price differences between the PJM/HUDS Interface and the NYIS/Hudson bus based on LMP differences and flow direction.

Table 9-35 PJM and NYISO flow based hours and price differences (Hudson): January through March, 2023

LMP Difference	Flow Direction	Number of Hours	Average Hourly Price Difference
NYIS/Hudson Bus LBMP > PJM/HUDS LMP	Total Hours	1,713	$15.90
	Consistent Flow (PJM to NYIS)	1,623	$16.28
	Inconsistent Flow (NYIS to PJM)	0	$0.00
	No Flow	90	$9.04
PJM/HUDS LMP > NYIS/Hudson Bus LBMP	Total Hours	446	$9.10
	Consistent Flow (NYIS to PJM)	0	$0.00
	Inconsistent Flow (PJM to NYIS)	438	$8.70
	No Flow	8	$31.37

To move power from PJM to NYISO on the Hudson Line, two PJM transmission service reservations are required. A transmission service reservation is required from the PJM Transmission System to the Hudson Line ("Out Service") and another transmission service reservation is required on the Hudson Line ("Hudson Service").[29] The PJM Out Service is covered by normal PJM OASIS business operations.[30] The Hudson Service falls under the provisions for controllable merchant facilities, Schedule 17 of the PJM Tariff. The Hudson Service is also acquired on the PJM OASIS.

Hudson Service is owned by a primary rights holder, and any nonfirm service that is not used (as defined by scheduled on a NERC Tag) may be released either voluntarily by the primary rights holder or by default by PJM. The primary rights holder may elect to voluntarily release monthly, weekly, daily or hourly firm or nonfirm service. Voluntarily releasing the service allows for the primary rights holder to specify a rate to be charged for the released service. If the primary rights holder elects to not voluntarily release nonfirm service, and does not use the service, the available transmission will be released by default at 1200 (EPT), one business day before the start of service.

28 The Linden VFT Line is a bidirectional facility. The "Total Capacity" lines represent the maximum amount of interchange possible in either direction. These lines were included to maintain a consistent scale, for comparison purposes, with the Neptune DC Tie Line.

29 See OASIS "PJM Business Practices for Hudson Transmission Service," <http://www.pjm.com/~/media/etools/oasis/merch-trans-facilities/htp-Business-practices.ashx>.

30 See OASIS "Regional Transmission and Energy Scheduling Practices," Rev. 11 (January 27, 2023) <http://www.pjm.com/~/media/etools/oasis/regional-practices-clean-doc.ashx>.

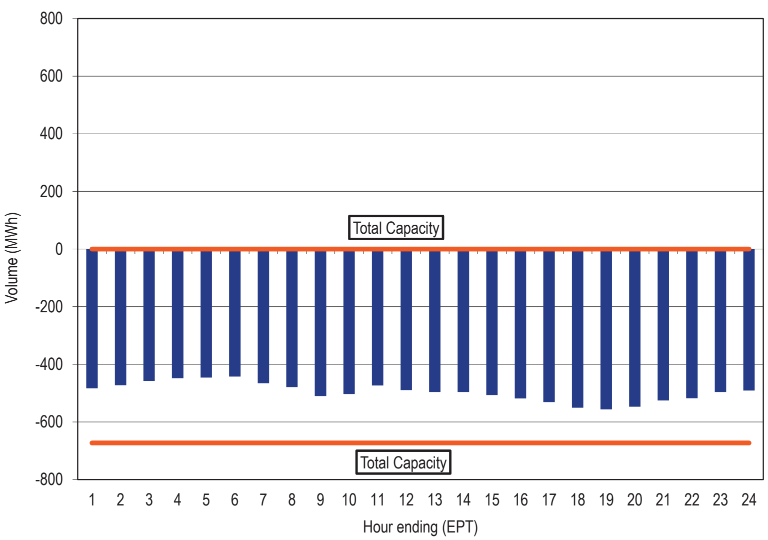
On March 31, 2023, the rate for the nonfirm service released by default was $10.00 per MWh. The primary rights holder remains obligated to pay for the released service unless a second transmission customer acquires the released service.

Table 9-36 shows the percent of scheduled interchange across the Hudson Line by the primary rights holder since commercial operations began in May, 2013. Table 9-36 shows that in the first three months of 2023, the primary rights holder was responsible for less than 100 percent of the scheduled interchange across the Hudson Line. Figure 9-9 shows the hourly average flow across the Hudson Line for the first three months of 2023.

Table 9-36 Percent of scheduled interchange across the Hudson Line by primary rights holder: May 2013 through March 2023[31]

	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
January	NA	51.22%	16.27%	100.00%	NA	24.44%	52.21%	29.70%	37.64%	64.30%	81.40%
February	NA	49.00%	14.67%	NA	NA	23.25%	77.12%	23.61%	47.37%	64.34%	82.72%
March	NA	40.40%	71.88%	NA	NA	9.55%	72.42%	87.24%	53.27%	82.65%	83.41%
April	NA	100.00%	100.00%	NA	NA	15.13%	100.00%	10.02%	70.90%	84.91%	
May	100.00%	26.87%	100.00%	100.00%	NA	92.18%	100.00%	20.53%	65.15%	84.15%	
June	100.00%	5.89%	59.72%	100.00%	NA	44.89%	44.98%	38.26%	73.81%	100.00%	
July	100.00%	18.51%	84.34%	NA	NA	16.26%	36.43%	27.56%	76.56%	100.00%	
August	100.00%	75.17%	65.48%	NA	NA	19.24%	43.10%	35.64%	59.09%	100.00%	
September	100.00%	75.31%	78.73%	NA	NA	22.90%	43.42%	30.75%	53.66%	100.00%	
October	100.00%	99.71%	18.65%	100.00%	NA	22.67%	33.60%	52.58%	56.26%	100.00%	
November	85.57%	99.60%	24.67%	100.00%	80.12%	50.44%	44.36%	38.60%	65.24%	68.68%	
December	28.32%	1.68%	100.00%	NA	21.93%	29.38%	41.78%	38.82%	61.11%	70.02%	

Figure 9-9 Hudson hourly average flow: January through March, 2023



31 The designation of "NA" means there was no flow on the Hudson Line during those months.

Interchange Activity During High Load Hours

The PJM metered system peak load during the first three months of 2023 was 117,705 MW in the HE 2000 (EPT) on February 3, 2023. PJM was a net scheduled exporter of energy in 22 of the 24 hours on February 3, 2023, with average hourly scheduled exports of 2,078 MW. During HE 2000 on February 3, 2023, PJM had net scheduled exports of 791 MW and net metered actual exports of 711 MW. Net transaction exports during this time were consistent with price differences between PJM and the NYISO and MISO and between the PJM/NEPT Interface and the NYIS/Neptune bus, the PJM/LIND Interface and the NYIS/Linden Bus and the PJM/HUDS Interface and the NYIS/Hudson Bus. During February 2023, PJM was a net scheduled exporter of energy in 666 of the 672 hours (99.1 percent). During February 2023, the average hourly scheduled interchange was -4,178 MW (representing 4.8 percent of the average hourly load of 87,804 MW in February 2023).

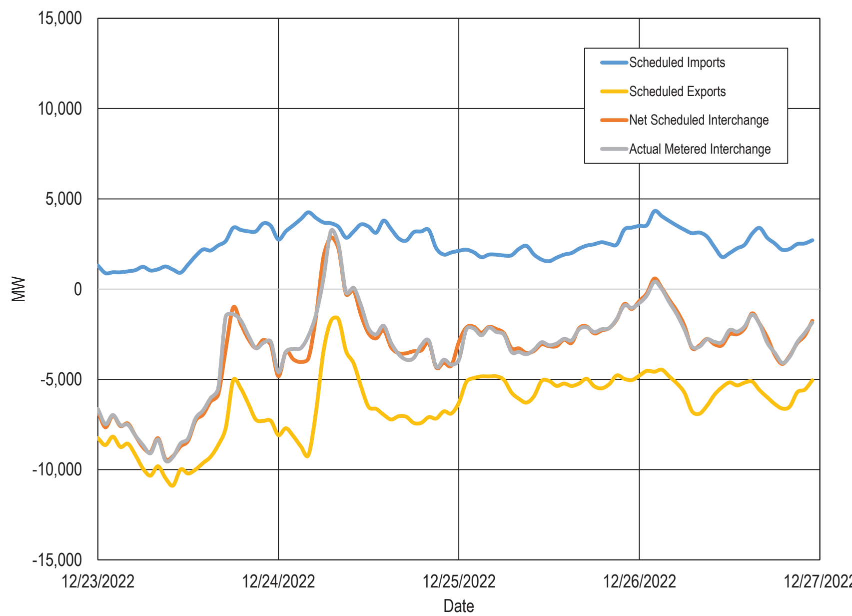
Winter Storm Elliott

Winter storm Elliott (Elliott) had a significant impact on PJM from December 23, 2022, through December 26, 2022, primarily as a result of low temperatures. Elliott affected interchange transaction volumes, resulted in large volumes of transaction curtailments and required the sale of emergency power to neighboring balancing authorities.

Interchange Volume

PJM was a net exporter of energy in 91 of the 96 hours (94.8 percent of all hours) from December 23, 2022 through December 26, 2022, with average hourly net scheduled exports of -3,221.8 MW, and average hourly metered exports of -3,267.1 MW. Three of the five hours of net imports occurred during hour ending (HE) 0700 (EPT) through HE 0900 (EPT) on December 24, 2022, and were the result of PJM's curtailment of export transactions during maximum generation emergency actions. During these three hours, PJM had average hourly scheduled imports of 1,832.9 MW. The other two hours of net imports occurred from HE 0300 (EPT) through HE 0400 (EPT) on December 26, 2022, and were the result of both an increase of scheduled imports and external balancing authority TLR curtailments of PJM export transactions. During these two hours, PJM had average hourly scheduled imports of 136.4 MW. Figure 9-10 shows the scheduled import volume, scheduled export volume and the net scheduled interchange volumes, as well as the actual net metered interchange for December 23, 2022 through December 26, 2022.

Figure 9-10 Interchange Volume: December 23, 2022 through December 26, 2022



While PJM was a net exporter of energy in 91 of the 96 hours (94.8 percent), PJM exports to individual neighboring control areas within contiguous balancing authorities varied. Table 9-37 shows the number of exporting hours at the individual NYISO interfaces, aggregate NYISO, the individual MISO interfaces, and aggregate MISO.

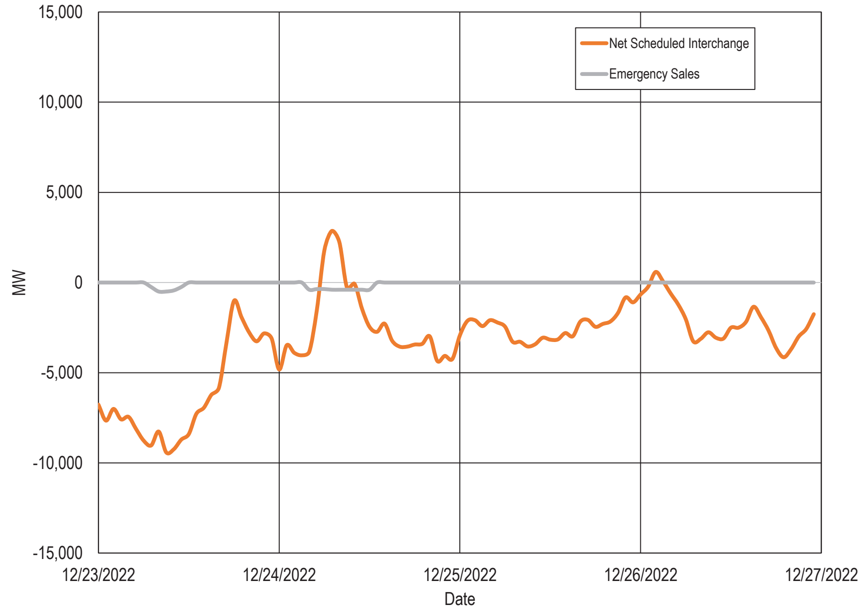
Table 9-37 Number of net exporting hours by balancing authority: December 23, 2022 through December 26, 2022

	Net Export Hours	Percent of all Hours
CPLE	42	43.8%
CPLW	96	100.0%
DUK	82	85.4%
LGEE	16	16.7%
MISO	96	100.0%
ALTE	17	17.7%
ALTW	45	46.9%
AMIL	93	96.9%
CIN	96	100.0%
CWLP	94	97.9%
IPL	96	100.0%
MEC	96	100.0%
MECS	0	0.0%
NIPS	96	100.0%
WEC	0	0.0%
NYISO	79	82.3%
HUDS	96	100.0%
LIND	96	100.0%
NEPT	95	99.0%
NYIS	48	50.0%
TVA	35	36.5%
PJM Net	91	94.8%

Emergency Sales

In addition to the scheduled interchange, PJM also made emergency sales to TVA during HE 0800 (EPT) through 1200 (EPT) (averaging 388.0 MW per hour) on December 23, 2022, and HE 0500 (EPT) through 1300 (EPT) (averaging 391.8 MW per hour) on December 24, 2022. Figure 9-11 shows the volume of emergency sales compared to the overall net scheduled interchange volume. Emergency sales are included in scheduled exports.

Figure 9-11 Emergency Sales Volume: December 23, 2022 through December 26, 2022



Interface Prices

Net transaction exports during the four day period from December 23, 2022 through December 26, 2022 were inconsistent with the price differences in 58 of the 96 hours (60.4 percent) between PJM and MISO. During this time, PJM's average hourly LMP at the PJM/MISO interface was $395.17, while the MISO average hourly LMP at the MISO/PJM interface was $235.08. The largest price difference with uneconomic flows at the PJM/MISO interface was $2,552.58 in HE 0500 (EPT) on December 24, 2022.

Net transaction exports during the four day period from December 23, 2022, through December 26, 2022 were inconsistent with the price differences in 41 of the 96 hours (42.7 percent) between PJM and the NYISO. During this time, PJM's average hourly LMP at the PJM/NYIS interface was $471.87, while the

NYISO average hourly LBMP at the NYIS/PJM interface was $286.40. The largest price difference with uneconomic flows at the PJM/NYIS interface was $1,240.12 in HE 1800 (EPT) on December 24, 2022.

Net transaction exports during the four day period from December 23, 2022, through December 26, 2022 were inconsistent with the price differences in 41 of the 96 hours (42.7 percent) between PJM and the Neptune proxy bus. During this time, PJM's average hourly LMP at the PJM/Neptune interface was $521.13, while the Neptune proxy bus average hourly LBMP was $389.55. The largest price difference with uneconomic flows at the PJM/Neptune interface was $3,205.90 in HE 0500 (EPT) on December 24, 2022.

Net transaction exports during the four day period from December 23, 2022, through December 26, 2022 were inconsistent with the price differences in 41 of the 96 hours (42.7 percent) between PJM and the Linden proxy bus. During this time, PJM's average hourly LMP at the PJM/Linden interface was $511.31, while the Linden proxy bus average hourly LBMP was $358.54. The largest price difference with uneconomic flows at the PJM/Linden interface was $3,116.30 in HE 0500 (EPT) on December 24, 2022.

Net transaction exports during the four day period from December 23, 2022, through December 26, 2022 were inconsistent with the price differences in 43 of the 96 hours (44.8 percent) between PJM and the Hudson proxy bus. During this time, PJM's average hourly LMP at the PJM/Hudson interface was $516.88, while the Hudson proxy bus average hourly LBMP was $359.24. The largest price difference with uneconomic flows at the PJM/Hudson interface was $3,112.94 in HE 0500 (EPT) on December 24, 2022.

Curtailments

Market prices provide an incentive to market participants to sell into the PJM region when PJM prices are higher than in neighboring areas, or buy from the PJM region when prices are lower than in neighboring areas. These incentives apply to potential new transactions and to ongoing transactions. But not all market participants respond to pricing signals, as interchange transactions can be entered using long term contractual arrangements under which volumes may not be affected by real time prices. As PJM redispatches generation to resolve internal and interface transmission constraints, the resulting LMPs provide economic signals to market participants to respond, and the transmission issues are resolved. As a result, PJM generally does not curtail interchange transactions to control transmission constraints. While PJM may also issue TLRs to resolve constraints affected by parallel flows created by transactions between neighboring balancing authorities, PJM has had little need to do so. In 2022, PJM issued only one TLR that required the curtailment of transactions (See Table 9-39). Most transactions that PJM curtails are at the direction of external balancing authorities through TLRs or neighboring balancing authority area directives resulting from their market clearing mechanisms. During emergency conditions, when economic incentives do not provide the needed results, PJM will follow emergency procedures and initiate the curtailment of interchange transactions to maintain system reliability.

Transmission Loading Relief Procedure (TLR)

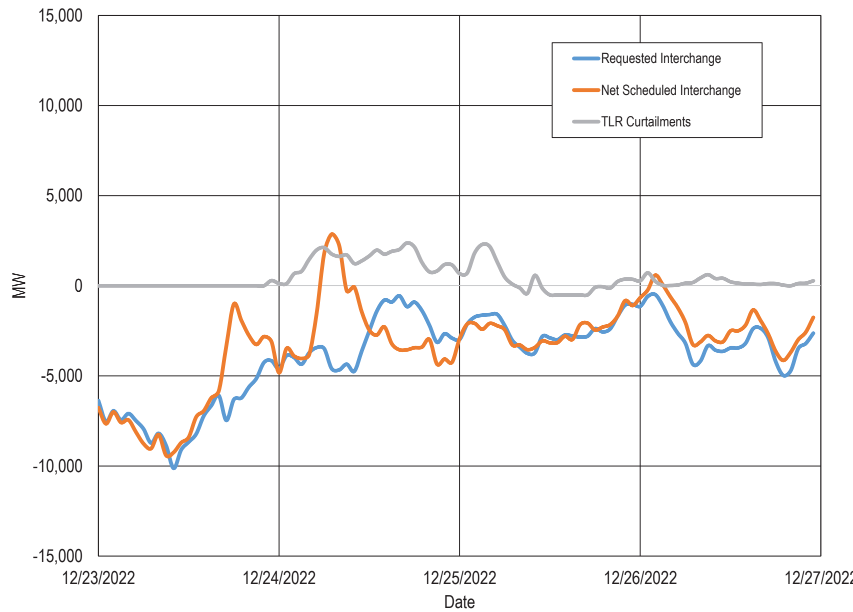
TLRs are called to control flows on internal and interface transmission facilities when economic redispatch cannot solve overloads on those facilities. TLRs are called to control flows from, to, and between external balancing authorities. When a TLR is issued, all transactions that have greater than a five percent distribution factor impact on the constraint are identified. Issuing a TLR gives balancing authority areas visibility to transactions between other external balancing authorities that affect their transmission system and to which they are not a party. These transactions are curtailed in transmission priority order until the necessary relief is obtained. TLRs are used more frequently in nonmarket areas, as economic redispatch of generation is not an option.

There are seven TLR levels and additional sublevels, determined by the severity of system conditions and whether the interchange transactions contributing to congestion on the affected flowgates are using firm or nonfirm transmission. Reliability coordinators are not required to implement TLRs in order. Curtailment of transactions using nonfirm transmission occur starting at TLR Level 3, and curtailment of transactions using firm transmission occur starting at TLR Level 5.[32]

32 Additional details regarding the TLR procedure can be found in NERC. "Reliability Standards for the Bulk Electric Systems of North America: *Standard IRO-006-5 – Reliability Coordination – Transmission Loading Relief*" (December 6, 2022) <https://www.nerc.com/pa/Stand/Reliability%20Standards%20Complete%20Set/RSCompleteSet.pdf>.

There were eight external balancing area TLRs issued from December 23, 2022, through December 26, 2022. Of those eight TLRs, five reached TLR Level 3A or higher and resulted in the curtailment of PJM interchange transactions. The five TLRs that resulted in curtailments were issued by MISO (two TLRs), TVA, NYISO and Ontario. These TLRs were issued to control flows on transmission facilities when economic redispatch could not solve overloads. The curtailment of transactions started in HE 2400 (EPT) on December 23, 2022, and continued through HE 2400 (EPT) on December 26, 2022, resulting in the curtailment of 55,134 MWh of import transactions and 8,800 MWh of export transactions. The net effect of TLR curtailments during this time was an average curtailment of 634.0 MW per hour of imports to PJM. Figure 9-12 shows the effects of the TLR curtailments on the overall net scheduled interchange volume. The curtailment of import transactions (the gray line) increased PJM net exports (the difference between the blue, requested interchange line, and the orange, net scheduled interchange line). The curtailment of export transactions had the opposite effect.

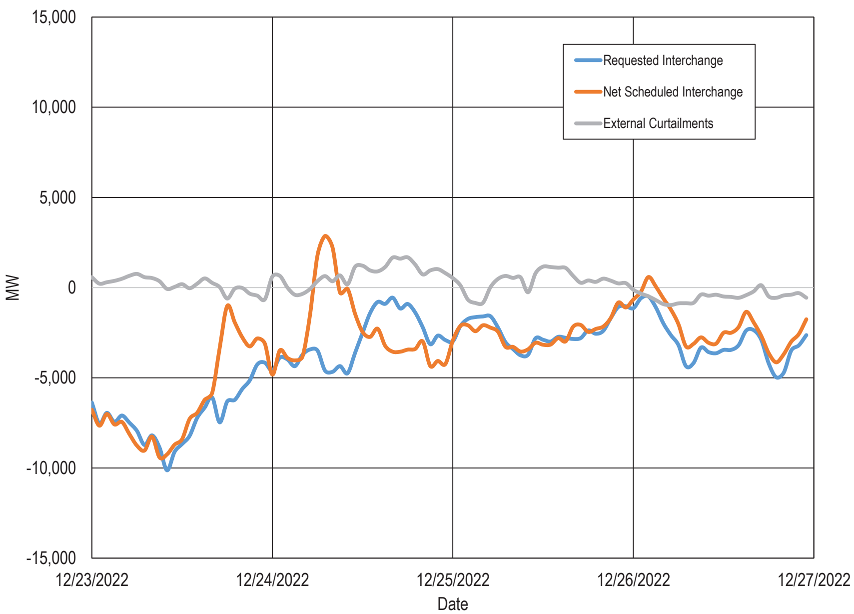
Figure 9-12 TLR Curtailment Volume: December 23, 2022 through December 26, 2022



Neighboring Balancing Authority Curtailments

Interchange volume in PJM can be affected by the curtailment of transactions by PJM's neighboring balancing authorities. Most curtailments requested by PJM's neighboring balancing authority areas are from the New York Independent System Operator (NYISO) and are the direct result of the NYISO's market clearing process. During the four day period from December 23, 2022, through December 26, 2022, there were curtailments of net imports to PJM in 58 of the 96 hours (60.0 percent), averaging 620 MW of import transactions per hour. Import curtailments contributed to PJM being a larger net exporter during those hours. There were curtailments of net exports from PJM in 38 of the 96 hours (40.0 percent), averaging 473 MW of export transactions in those hours. Export curtailments contributed to PJM being a larger net importer during those hours. Figure 9-12 shows the net hourly curtailment volume resulting from PJM's neighboring balancing authority curtailments (the gray line). The effect of these curtailments on net interchange is the difference between the blue, requested interchange line, and the orange, net scheduled interchange line.

Figure 9-13 Neighbor Balancing Area Curtailment Volume: December 23, 2022 through December 26, 2022



PJM Reliability Curtailments

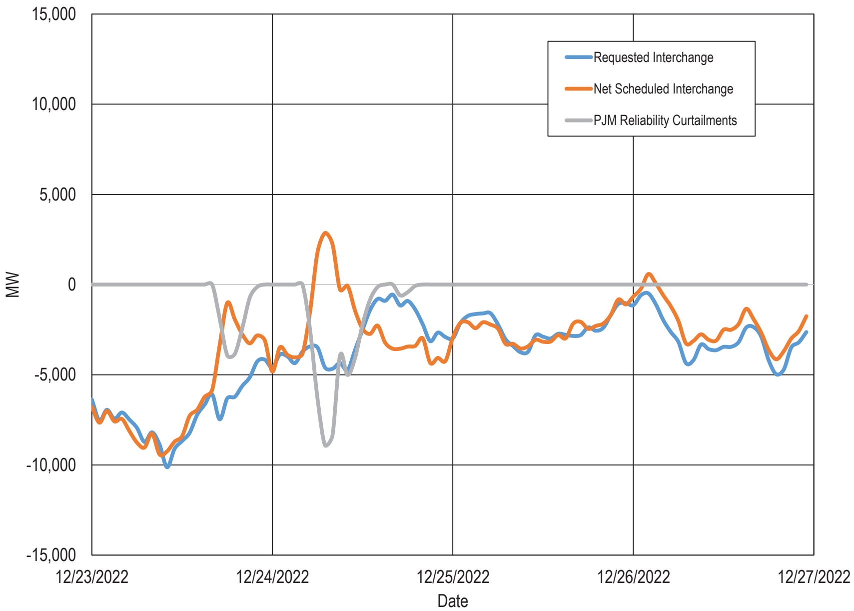
PJM's interchange transaction business rules do not define or use unit specific tags. PJM's interchange transaction exports are sales of system energy from the generation resources that are running at the time. PJM may curtail transactions scheduled on nonfirm and firm transmission when an emergency or other unforeseen conditions threaten the reliability of the transmission system.[33] The order of transaction curtailments is determined based on transmission priority order, but PJM may deviate from that order as necessary to maintain the reliability of the transmission system.

Starting HE 1800 (EPT) on December 23, 2022, and continuing through HE 2000 (EPT) on December 24, 2022, PJM issued several curtailments under the maximum generation emergency actions procedures. These actions resulted in 56,258.3 MWh of transaction curtailments, averaging 2,086.6 MW per hour.[34] Of the 56,258.3 MWh, 41,938.3 MWh (74.5 percent) were on nonfirm transmission, and 14,320.0 MWh (25.5 percent) were on firm transmission. Figure 9-14 shows the effects of the PJM reliability curtailments on the overall net scheduled interchange volume. The largest volume of PJM curtailments occurred between HE 0700 (EPT) and HE 1100 (EPT) on December 24, 2022. During this time, PJM experienced a large volume of generation outages. The lack of internal supply required PJM to curtail additional export transactions under maximum emergency actions in order to maintain reliability. The curtailment of export transactions (the gray line) resulted in PJM becoming a larger net importer (the difference between the blue, requested interchange line, and the orange, net scheduled interchange line).

33 OATT § 13.6 and 14.7.

34 See PJM. "Manual 13: Emergency Operations," Rev. 86 (November 3, 2022).

Figure 9-14 PJM Reliability Curtailment Volume: December 23, 2022 through December 26, 2022



Capacity Backed Export Transactions

PJM's interchange transaction business rules do not define or use unit specific tags. Generators that sell capacity from specific PJM units to an external balancing authority rather than in the PJM capacity market are instructed to identify the associated energy exports by flagging the transaction with the "CAPBACK" (capacity backed) exception.

A pseudo tie is required for an external unit to sell its capacity into the PJM capacity market. The PJM pseudo tie requirement is designed to help ensure that external resources are full substitutes for internal PJM capacity resources and that PJM has dispatch control over the energy from the external capacity resources. This ensures that the energy output belongs to PJM by incorporating that energy output in PJM's Area Control Error (ACE). These requirements cannot be met with a tagged interchange transaction.

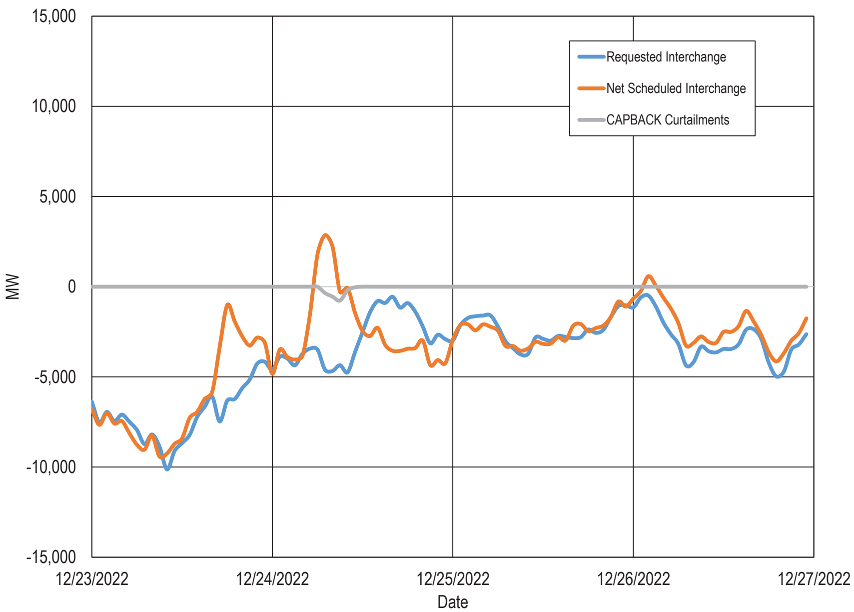
External balancing authorities that accept anything less than the equivalent of a pseudo tie when relying on capacity purchased from PJM resources also accept the risk that the interchange transaction could be curtailed. Nevertheless, PJM attempts to cooperate with their neighbors by communicating the intent to curtail transactions designated as capacity backed.

PJM did not invoke emergency step 7, which includes recalls of the energy from "any external capacity" during Elliott.[35] On December 24, 2022, between HE 0800 (EPT) and 1200 (EPT), after coordination with neighboring balancing areas, PJM curtailed transactions with the CAPBACK exception. The CAPBACK exception curtailments totaled 1,904 MWh over that five hour period with an average hourly curtailment volume of 381 MWh. Figure 9-21 shows the volume of CAPBACK exception curtailments initiated by PJM under the maximum emergency action compared to the overall net scheduled interchange volume. These curtailments are included in the PJM reliability curtailments, but shown separately to highlight the relative volume.

PJM's authority to recall capacity backed exports is not defined clearly enough. PJM's authority to recall capacity backed exports when the relevant capacity is not producing energy is not clearly defined. The MMU recommends that PJM have clear rules governing when PJM may recall capacity backed exports.

35 See PJM. "Manual 13: Emergency Operations," § 2.3.2, page 38, Rev. 86 (November 3, 2022).

Figure 9-15 PJM CAPBACK Curtailment Volume: December 23, 2022 through December 26, 2022



Export Transactions Backed by PJM Capacity Resources

One of the obligations of PJM capacity resources is that energy output from such resources is recallable by PJM in an emergency. The logic is that the capacity has Capacity Interconnection Rights (CIRs) and that PJM load paid for the capacity and has first call on the energy from the capacity resources when needed. It is not clear why PJM did not recall the energy output from all PJM capacity resources during Elliott. OA 1.10.6(c) states that PJM may curtail deliveries to an External Market Buyer if necessary to maintain reliability. Manual 13 states that during reserve emergencies, PJM may implement defined measures to maintain reliability, including "recalling non-capacity backed off-system sales."[36] Emergency Step 4A includes PJM actions related to such exports, including determining the feasibility of cutting such exports and determining the impact on affected balancing authorities. Step 4A states that such curtailments should not be made if they would cause load shed in affected balancing authorities unless not cutting would cause load shed in PJM. Under Step 7, PJM "recalls any external capacity."

36 See PJM. "Manual 13: Emergency Operations," § 2.3.2, Rev. 86 (November 3, 2022).

It is essential that PJM have the ability to manage curtailments as needed in emergency conditions. It is also essential that PJM have clear rules so that market participants and PJM understand the process when an emergency occurs. The MMU recommends that PJM have clear rules governing when PJM will recall the energy output from PJM capacity resources.

Operating Agreements with Bordering Areas

To improve reliability and reduce potential seams issues, PJM and its neighbors have developed operating agreements, including: operating agreements with MISO and the NYISO; a reliability agreement with TVA; an operating agreement with Duke Energy Progress, Inc.; a reliability coordination agreement with VACAR South; a balancing authority operations agreement with the Wisconsin Electric Power Company (WEC); and a Northeastern planning coordination protocol with NYISO and ISO New England.

Table 9-38 shows a summary of the elements included in each of the operating agreements PJM has with its bordering areas.

Table 9-38 Summary of elements included in operating agreements with bordering areas

Agreement:	PJM-MISO	PJM-NYISO	PJM-TVA	PJM-DEP	PJM-VACAR	PJM-WEP	Northeastern Protocol
Data Exchange							
Real-Time Data	YES	YES	YES	YES	YES	YES	NO
Projected Data	YES	YES	YES	YES	NO	NO	NO
SCADA Data	YES	YES	YES	YES	NO	NO	NO
EMS Models	YES	YES	YES	YES	NO	NO	YES
Operations Planning Data	YES	YES	YES	YES	NO	NO	YES
Available Flowgate Capability Data	YES	YES	YES	YES	NO	NO	YES
Near-Term System Coordination							
Operating Limit Violation Assistance	YES	YES	YES	YES	YES	NO	NO
Over/Under Voltage Assistance	YES	YES	YES	YES	YES	NO	NO
Emergency Energy Assistance	YES	YES	NO	YES	YES	NO	NO
Outage Coordination	YES	YES	YES	YES	YES	NO	NO
Long-Term System Coordination	YES	YES	YES	YES	NO	NO	YES
Congestion Management Process							
ATC Coordination	YES	YES	YES	YES	NO	NO	NO
Market Flow Calculations	YES	YES	YES	NO	NO	NO	NO
Firm Flow Entitlements	YES	YES	YES	NO	NO	NO	NO
Market to Market Redispatch	YES - Redispatch	YES - Redispatch	NO	NO	NO	NO	NO
Joint Checkout Procedures	YES	YES	YES	YES	NO	YES	NO

PJM-MISO = MISO/PJM Joint Operating Agreement
PJM-NYISO = New York ISO/PJM Joint Operating Agreement
PJM-TVA = Joint Reliablity Coordination Agreement Between PJM - Tennessee Valley Authority (TVA)
PJM-DEP = Duke Energy Progress (DEP) - PJM Joint Operating Agreement
PJM-VACAR = PJM-VACAR South Reliability Coordination Agreement
PJM-WEP = Balancing Authority Operations Coordination Agreement Between Wisconsin Electric Power Company and PJM Interconnection, LLC
Northeastern Protocol = Northeastern ISO-Regional Transmission Organization Planning Coordination Protocol

PJM and MISO Joint Operating Agreement[37]

The Joint Operating Agreement between MISO and PJM Interconnection, L.L.C. was executed on December 31, 2003. The PJM/MISO JOA includes provisions for market based congestion management that, for designated flowgates within MISO and PJM, allow for redispatch of units within the PJM and MISO regions to jointly manage congestion on these flowgates and to assign the costs of congestion management appropriately. In 2012, MISO and PJM initiated a joint stakeholder process to address issues associated with the operation of the markets at the seam.[38]

Under the market to market rules, the organizations coordinate pricing at their borders. PJM and MISO each calculate an interface LMP using network models including distribution factor impacts. PJM uses 10 buses along the PJM/MISO border to calculate the PJM/MISO interface pricing point LMP. Prior to June 1, 2017, MISO used all of the PJM generator buses in its model of the PJM system in its calculation of the MISO/PJM interface pricing point.[39] On June 1, 2017, MISO modified their MISO/PJM interface definition to match PJM's PJM/MISO interface definition.

An operating entity is an entity that operates and controls a portion of the bulk transmission system with the goal of ensuring reliable energy interchange between generators, loads and other operating entities.[40] Coordinated flowgates are identified to determine which flowgates an operating entity affects significantly. This set of flowgates may then be used in the congestion management process. An operating entity will conduct sensitivity studies to determine which flowgates are significantly affected by the flows of the operating entity's control zones (historic control areas that existed in the IDC). An operating entity identifies these flowgates by performing five studies to determine which flowgates the operating entity will monitor and help control. These studies include generation to load distribution factor studies, transfer distribution factor analysis and an external asynchronous resource study. An operating entity may also specify additional flowgates that

37 See "Joint Operating Agreement Between the Midwest Independent Transmission System Operator, Inc. and PJM Interconnection, L.L.C.," (December 11, 2008) <http://www.pjm.com/directory/merged-tariffs/miso-joa.pdf>.

38 See "PJM/MISO Joint and Common Market Initiative," <http://www.pjm.com/committees-and-groups/stakeholder-meetings/pjm-miso-joint-common.aspx>.

39 See the *2012 State of the Market Report for PJM*, Volume II, Section 8, "Interchange Transactions," for a more detailed discussion.

40 See "Joint Operating Agreement Between the Midwest Independent Transmission System Operator, Inc. and PJM Interconnection, L.L.C.," (December 11, 2008) <http://www.pjm.com/directory/merged-tariffs/miso-joa.pdf>.

have not passed any of the five studies to be coordinated flowgates where the operating entity expects to use the TLR process to manage congestion.[41] A reciprocal coordinated flowgate (RCF) is a CF that is monitored and controlled by PJM or MISO, on which both have significant impacts. Only RCFs are subject to the market to market congestion management process.

As of January 1, 2023, PJM had 197 flowgates eligible for M2M (Market to Market) coordination. In the first three months of 2023, PJM added one flowgate and deleted six flowgates, resulting in 192 flowgates eligible for M2M coordination as of March 31, 2023. As of January 1, 2023, MISO had 144 flowgates eligible for M2M coordination. In the first three months of 2023, MISO added 17 flowgates and deleted 34 flowgates, resulting in 127 flowgates eligible for M2M coordination as of March 31, 2023.

The firm flow entitlement (FFE) represents the amount of historic 2004 flow that each RTO had created on each RCF used in the market to market settlement process. The FFE establishes the amount of market flow that each RTO is permitted to create on the RCF before incurring redispatch costs during the market to market process. If the nonmonitoring RTO's real-time market flow is greater than their FFE plus the approved MW adjustment from day-ahead coordination, then the nonmonitoring RTO will pay the monitoring RTO based on the difference between their market flow and their FFE. If the nonmonitoring RTO's real-time market flow is less than their FFE plus the approved MW adjustment from day-ahead coordination, then the monitoring RTO will pay the nonmonitoring RTO for congestion relief provided by the nonmonitoring RTO based on the difference between the nonmonitoring RTO's market flow and their FFE.

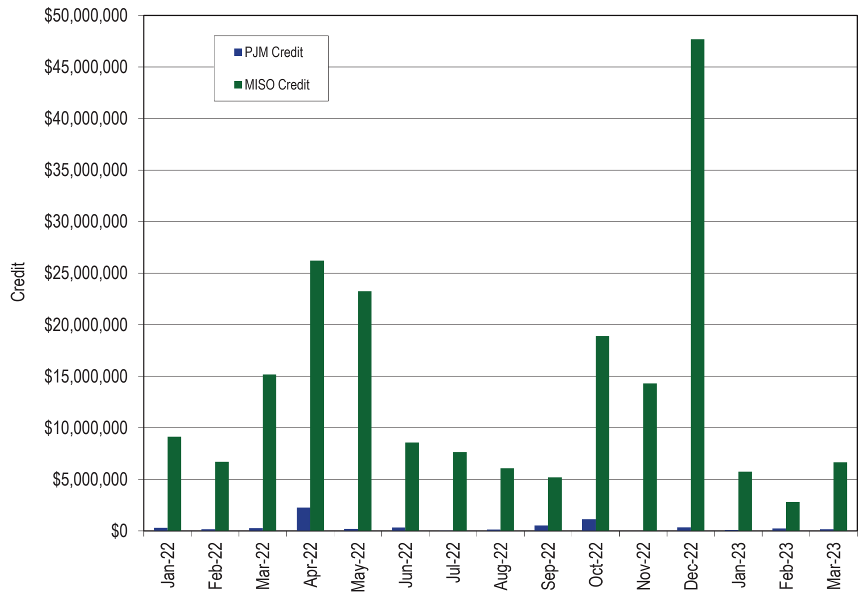
April 1, 2004, known as the freeze date, is used to determine the firm rights on flowgates based on historic premarket firm flows as of that date. In the past 16 years, topology and market changes have occurred, making the 2004 flows irrelevant in 2023. The RTOs and stakeholders recognize that a modification to the freeze date is necessary.[42] PJM and MISO stakeholders have spent several years on the freeze date issues. Discussions regarding the Firm Flow Limit (FFL) solutions between market and nonmarket areas are also ongoing. No resolution to these issues appears imminent. The final resolution to the freeze date alternative should account for the investments made by each RTO in the transmission system. The MMU recommends modifications to the FFE calculation to ensure that FFE calculations reflect the current capability of the transmission system as it evolves. The MMU recommends that the Commission set a deadline for PJM and MISO to resolve the FFE freeze date and related issues.

In the first three months of 2023, market to market operations resulted in MISO and PJM redispatching units to control congestion on M2M flowgates and the exchange of payments for this redispatch. Figure 9-16 shows credits for coordinated congestion management between PJM and MISO. The large settlements in December 2022 were due to the large amount of congestion and high LMPs observed during Elliott.

41 See "Joint Operating Agreement Between the Midwest Independent Transmission System Operator, Inc. and PJM Interconnection, L.L.C.," (December 11, 2008) <http://www.pjm.com/directory/merged-tariffs/miso-joa.pdf>.

42 See "*Freeze Date Alternatives*," (May 21, 2019) <https://www.pjm.com/-/media/committees-groups/stakeholder-meetings/pjm-miso-joint-common/20190521/20190521-item-01-freeze-date-update.ashx>.

Figure 9-16 PJM/MISO credits for coordinated congestion management: January 2022 through March 2023[43]



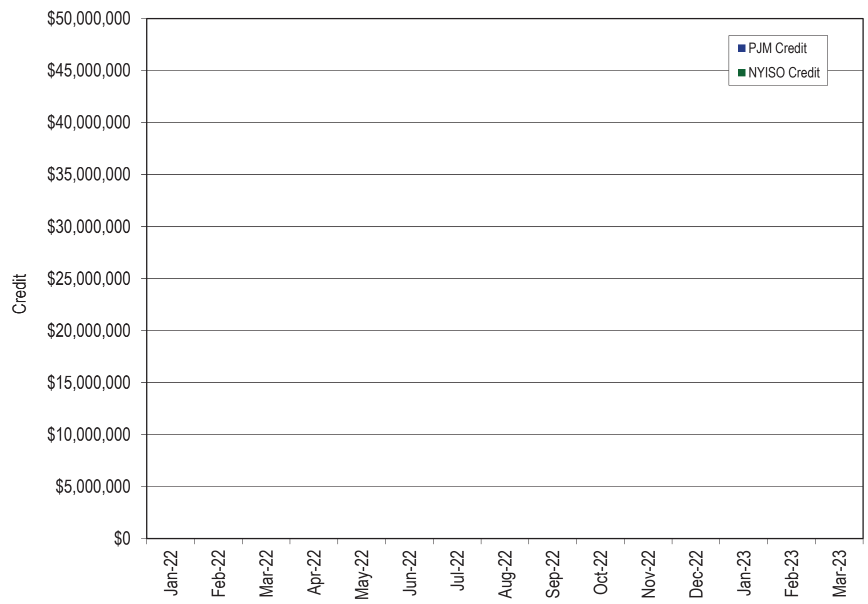
PJM and New York Independent System Operator Joint Operating Agreement (JOA)[44]

The Joint Operating Agreement between NYISO and PJM Interconnection, L.L.C. became effective on January 15, 2013. Under the market to market rules, the organizations coordinate pricing at their borders.

On June 28, 2019, NYISO and PJM submitted revisions to the NYISO-PJM Joint Operating Agreement (JOA). The revisions would address RTO concerns identified in their joint request for limited waiver of the JOA to authorize redispatch of generation in PJM. The intent of the redispatch would be to mitigate post-contingency overloads of transmission equipment on the New York side of the East Towanda-Hillside 230 kV Transmission Line. The agreement allows for the RTOs to control for this contingency without the exchange of payments for redispatch.[45]

In the first three months of 2023, market to market operations did not result in NYISO and PJM redispatching units to control congestion on M2M flowgates. Therefore, there was no exchange of payments for redispatch in the first three months of 2023. Figure 9-17 shows credits for coordinated congestion management between PJM and NYISO.

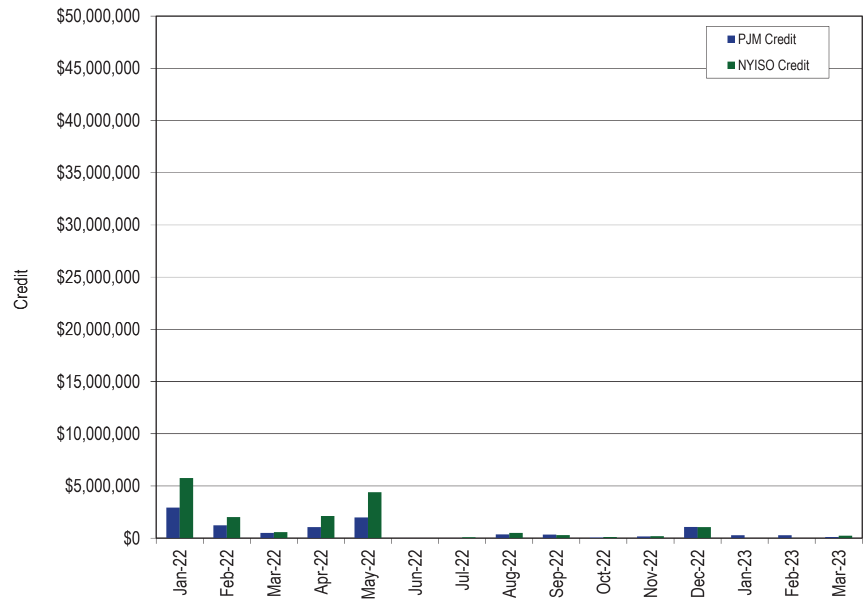
Figure 9-17 PJM/NYISO credits for coordinated congestion management (flowgates): January 2022 through March 2023[46]



43 The totals represented in this figure represent the settlements as of the time of this report and may not include adjustments or resettlements.
44 See "New York Independent System Operator, Inc., Joint Operating Agreement with PJM Interconnection, L.L.C.," (September 16, 2019) <http://www.pjm.com/~/media/documents/agreements/nyiso-joa.ashx>.
45 See NYISO Filing, FERC Docket No. ER19-2282-000 (June 28, 2019).
46 The totals represented in this figure represent the settlements as of the time of this report and may not include adjustments or resettlements.

The M2M coordination process focuses on real-time market coordination to manage transmission limitations that occur on M2M flowgates in a cost effective manner. Coordination between NYISO and PJM includes not only joint redispatch, but also incorporates coordinated operation of the PARs that are located at the PJM/NYIS border. This real-time coordination results in an efficient economic dispatch solution across both markets to manage the real-time transmission constraints that impact both markets, focusing on the actual flows in real time to manage constraints.[47] For each M2M flowgate, a PAR settlement will occur for each interval during coordinated operations. The PAR settlements are determined based on whether the measured real-time flow on each of the PARs is greater than or less than the calculated target value. If the actual flow is greater than the target flow, NYISO will make a payment to PJM. This payment is calculated as the product of the M2M flowgate shadow price, the PAR shift factor and the difference between the actual and target PAR flow. If the actual flow is less than the target flow, PJM will make a payment to NYISO. This payment is calculated as the product of the M2M flowgate shadow price, the PAR shift factor and the difference between the target and actual PAR flow. Effective May 1, 2017, coincident with the termination of the ConEd wheel, PJM and NYISO began M2M coordination at all of the PARs along the PJM/NYISO seam. Prior to May 1, 2017, only the Ramapo PARs were included in the M2M process. In the first three months of 2023, market to market operations resulted in NYISO and PJM adjusting PARs to control congestion and the exchange of payments for this coordination. Figure 9-18 shows the PAR credits for coordinated congestion management between PJM and NYISO.

Figure 9-18 PJM/NYISO credits for coordinated congestion management (PARs): January 2022 through March 2023[48]



PJM and TVA Joint Reliability Coordination Agreement (JRCA)[49]

The joint reliability coordination agreement (JRCA) executed on April 22, 2005, provides for the exchange of information and the implementation of reliability and efficiency protocols between TVA and PJM. The agreement also provides for the management of congestion and arrangements for both near-term and long-term system coordination. Under the JRCA, PJM and TVA honor constraints on the other's flowgates in their Available Transmission Capability (ATC) calculations. Market flows are calculated on reciprocal flowgates. When a constraint occurs on a reciprocal flowgate within TVA, PJM has the option to redispatch generation to reduce market flow, and therefore alleviate the

47 See "New York Independent System Operator, Inc., Joint Operating Agreement with PJM Interconnection, L.L.C.," (September 16, 2019) <http://www.pjm.com/~/media/documents/agreements/nyiso-joa.ashx>.

48 The totals represented in this figure represent the settlements as of the time of this report and may not include adjustments or resettlements.

49 See "Joint Reliability Coordination Agreement Among and Between PJM Interconnection, L.L.C., and Tennessee Valley Authority," (October 15, 2014) <http://www.pjm.com/~/media/documents/agreements/joint-reliability-coordination-agreement-miso-pjm-tva.ashx>.

constraint. Unlike the M2M procedure between MISO and PJM, this redispatch does not result in M2M payments. However, electing to redispatch generation within PJM can avoid potential market disruption by curtailing transactions under the Transmission Line Loading Relief (TLR) procedure to achieve the same relief. In 2022, PJM and TVA began discussions to add Louisville Gas and Electric Company (LG&E) and Kentucky Utilities (KU) as parties to the JRCA. The revisions to add LG&E and KU to the agreement are expected to be filed with the Commission in the second quarter of 2023. The agreement remained in effect in the first three months of 2023.

PJM and Duke Energy Progress, Inc. Joint Operating Agreement[50]

On September 9, 2005, FERC approved a JOA between PJM and Progress Energy Carolinas, Inc. (PEC), with an effective date of July 30, 2005. As part of this agreement, both parties agreed to develop a formal congestion management protocol (CMP). On February 2, 2010, PJM and PEC filed a revision to include a CMP under Article 14 of the JOA.[51] On January 20, 2011, the Commission conditionally accepted the compliance filing. On July 2, 2012, Duke Energy and Progress Energy Inc. completed a merger. At that time, Progress Energy Carolinas Inc., now a subsidiary of Duke Energy, changed its name to Duke Energy Progress (DEP).

On May 20, 2019, PJM and DEP submitted revisions to the JOA to delete Article 14.[52] PJM and DEP requested an effective date of July 22, 2019, for the filed revisions. On July 2, 2019, the Commission issued a letter order accepting the revisions to the JOA to delete the congestion management agreement effective July 22, 2019.[53]

PJM and VACAR South Reliability Coordination Agreement[54]

On May 23, 2007, PJM and VACAR South (comprised of Duke Energy Carolinas, LLC (DUK), DEP, South Carolina Public Service Authority (SCPSA), Southeast Power Administration (SEPA), South Carolina Energy and Gas Company (SCE&G) and Yadkin Inc. (part of Alcoa)) entered into a reliability coordination agreement which provides for system and outage coordination, emergency procedures and the exchange of data. The parties meet on a yearly basis. The agreement remained in effect in the first three months of 2023.

Balancing Authority Operations Coordination Agreement between Wisconsin Electric Power Company (WEC) and PJM Interconnection, LLC[55]

The Balancing Authority Operations Coordination Agreement executed on July 20, 2013, provides for the exchange of information between WEC and PJM. The purpose of the data exchange is to allow for the coordination of balancing authority actions to ensure the reliable operation of the systems. The agreement remained in effect in the first three months of 2023.

Northeastern ISO-Regional Transmission Organization Planning Coordination Protocol[56]

The Northeastern ISO-RTO Planning Coordination Protocol executed on December 8, 2004, provides for the exchange of information among PJM, NYISO and ISO New England. The purpose of the data exchange is to allow for the long-term planning coordination among and between the ISOs and RTOs in the Northeast. The agreement remained in effect in the first three months of 2023.

50 See "Amended and Restated Joint Operating Agreement Among and Between PJM Interconnection, L.L.C., and Duke Energy Progress Inc.," (July 22, 2019) <http://www.pjm.com/directory/merged-tariffs/progress-joa.pdf>.
51 See *PJM Interconnection, L.L.C and Progress Energy Carolinas, Inc.* Docket No. ER10-713-000 (February 2, 2010).
52 See *PJM Interconnection, L.L.C*, Docket No. ER19-1905-000 (May 20, 2019).
53 FERC Docket No. ER19-1905-000.
54 See "PJM-VACAR South RC Agreement," (November 7, 2014) <http://www.pjm.com/~/media/documents/agreements/executed-pjm-vacar-rc-agreement.ashx>.
55 See "Balancing Authority Operations Coordination Agreement between Wisconsin Electric Power Company and PJM Interconnection, L.L.C.," (July 20, 2013) <https://www.pjm.com/directory/merged-tariffs/rs43.pdf>.
56 See "Northeastern ISO/RTO Planning Coordination Protocol," (December 8, 2004) <http://www.pjm.com/~/media/documents/agreements/northeastern-iso-rto-planning-coordination-protocol.ashx>.

Interchange Transaction Issues

PJM Transmission Loading Relief Procedures (TLRs)

TLRs are called to control flows on electrical facilities when economic redispatch cannot solve overloads on those facilities. TLRs are called to control flows related to external balancing authorities, as redispatch within an LMP market can generally resolve overloads on internal transmission facilities.

The number of PJM issued TLRs of level 3a or higher was zero in the first three months of 2022 and zero in the first three months of 2023.[57]

The number of MISO issued TLRs of level 3a or higher decreased from 21 in the first three months of 2022 to one in the first three months of 2023. The number of different flowgates for which MISO declared a TLR 3a was four in the first three months of 2022, and one in the first three months of 2023. The total MWh of transaction curtailments decreased by 92.3 percent from 3,983 MWh in the first three months of 2022 to 306 MWh in the first three months of 2023.

The number of NYISO issued TLRs of level 3a or higher decreased from 18 in the first three months of 2022 to 10 in the first three months of 2023. The number of different flowgates for which NYISO declared a TLR 3a or higher was one in the first three months of 2022, and one in the first three months of 2023. The total MWh of transaction curtailments increased by 51.3 percent from 131,331 MWh in the first three months of 2022, to 63,968 MWh in the first three months of 2023.

57 TLR Level 3a is the first level of TLR that results in the curtailment of transactions. See the *2020 State of the Market Report for PJM*, Volume II, Appendix E, "Interchange Transactions," for a more complete discussion of TLR levels.

Table 9-39 PJM, MISO, and NYISO TLR procedures: January through March, 2023[58]

	Number of TLRs Level 3 and Higher			Number of Unique Flowgates That Experienced TLRs			Curtailment Volume (MWh)		
Month	PJM	MISO	NYISO	PJM	MISO	NYISO	PJM	MISO	NYISO
Jan	0	0	4	0	0	1	0	0	19,810
Feb	0	0	6	0	0	1	0	0	44,158
Mar	0	1	0	0	1	0	0	306	0
Total	0	1	10	0	1	1	0	306	63,968

Table 9-40 Number of TLRs by TLR level by reliability coordinator: January through March, 2023[59]

Year	Reliability Coordinator	3a	3b	4	5a	5b	6	Total
2023	MISO	1	0	0	0	0	0	1
	NYIS	10	0	0	0	0	0	10
	ONT	1	0	0	0	0	0	1
	PJM	0	0	0	0	0	0	0
	SOCO	3	2	0	0	0	0	5
	SWPP	2	0	0	1	5	0	8
	TVA	5	6	0	5	1	0	17
	VACS	0	0	0	0	0	0	0
Total	0	22	8	0	6	6	0	42

Up To Congestion Transactions

The original purpose, in 2000, of up to congestion transactions (UTC) was to allow market participants to submit a maximum congestion charge, up to $25 per MWh, they were willing to pay on an import, export or wheel through transaction in the day-ahead energy market. This product was offered as a tool for market participants to limit their congestion exposure on scheduled transactions in the real-time energy market.[60]

Up to congestion transactions affect the day-ahead dispatch and unit commitment. Despite that, up to congestion transactions were not required

58 The total row in the columns of the number of unique flowgates that experience TLRs are not a sum of the individual months. The total row represents the number of unique flowgates that have experienced TLRs for the year to date.

59 Southern Company Services, Inc. (SOCO) is the reliability coordinator covering a portion of Mississippi, Alabama, Florida and Georgia. Southwest Power Pool (SWPP) is the reliability coordinator for SPP. VACAR-South (VACS) is the reliability coordinator covering a portion of North Carolina and South Carolina.

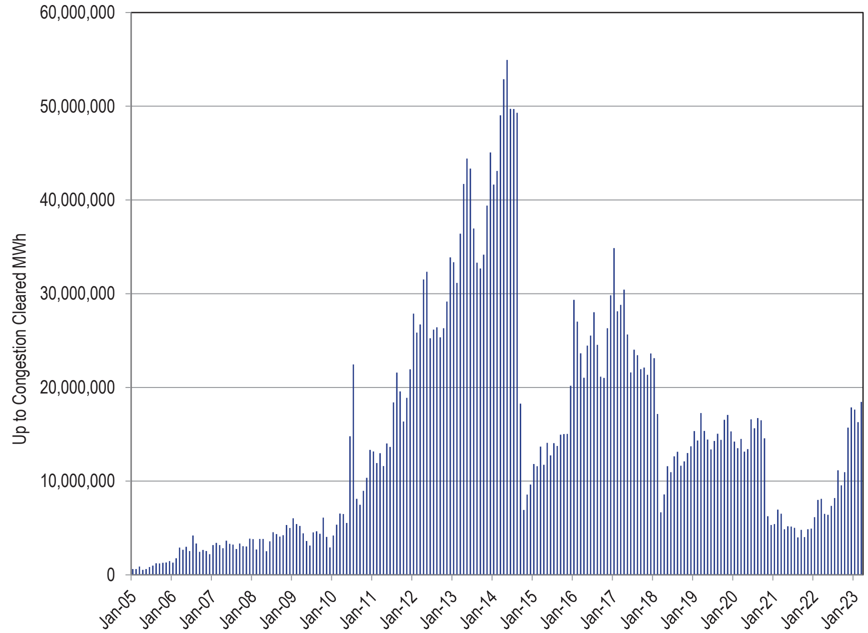
60 See the *2012 State of the Market Report for PJM*, Volume II, Section 8, "Interchange Transactions," for a more detailed discussion.

to pay uplift charges from their introduction in 2010 through October 31, 2020. On July 16, 2020, FERC issued an Order directing PJM to revise uplift allocation rules to allocate uplift to one side of up to congestion transactions.[61] The Order requires PJM to treat an up to congestion transaction, for uplift allocation purposes, as if the up to congestion transaction were equivalent to a DEC at its sink point. On November 1, 2020, PJM began allocating uplift to up to congestion transactions. Up to congestion transactions also negatively affect FTR funding.[62]

Up to congestion transaction volumes decreased following the allocation of uplift charges to UTCs effective November 1, 2020. The average cleared volume of up to congestion bids submitted in the day-ahead energy market decreased by 19.1 percent, from 495,001 MWh per day in the 12 month period prior to the allocation of uplift charges (November 1, 2019, through October 31, 2020), to 400,244 MWh per day for the most recent 12 month period (April 1, 2022 through March 31, 2023). While the volume of UTCs has increased in recent months, the volume of UTCs remains well below the levels prior to the allocation of uplift charges.

The average number of up to congestion bids submitted in the day-ahead energy market increased by 132.8 percent, from 33,055 bids per day in the first three months of 2022 to 76,959 bids per day in the first three months of 2023. The average number of up to congestion bids cleared in the day-ahead energy market increased by 79.5 percent, from 12,976 bids per day in the first three months of 2022 to 23,294 bids per day in the first three months of 2023. The average volume of up to congestion bids submitted in the day-ahead energy market increased by 186.2 percent, from 760,347 MWh per day in the first three months of 2022, to 2,175,774 MWh per day in the first three months of 2023. The average cleared volume of up to congestion bids submitted in the day-ahead energy market increased by 135.2 percent, from 247,428 MWh per day in the first three months of 2022, to 582,009 MWh per day in the first three months of 2023.

Figure 9-19 Monthly up to congestion cleared bids in MWh: January 2005 through March 2023



61 172 FERC ¶ 61,046 (2020).
62 See the *2023 Quarterly State of the Market Report for PJM: January through March*, Section 13: FTRs and ARRs, "FTR Forfeitures" for more information on up to congestion transaction impacts on FTRs.

Table 9-41 Monthly volume of cleared and submitted up to congestion bids: January 2022 through March 2023

	Bid MW					Bid Volume				
Month	Import	Export	Wheel	Internal	Total	Import	Export	Wheel	Internal	Total
Jan-22	2,202,600	3,227,026	340,408	15,650,585	21,420,619	96,598	149,612	14,586	723,140	983,936
Feb-22	1,722,657	3,131,256	435,011	15,800,392	21,089,315	91,078	159,021	20,491	705,112	975,702
Mar-22	4,533,781	2,091,884	566,832	18,728,804	25,921,300	127,118	139,469	19,080	729,625	1,015,292
Apr-22	3,643,833	1,846,211	680,033	20,758,140	26,928,216	125,219	78,307	11,426	750,929	965,881
May-22	3,114,660	1,387,494	386,182	20,640,018	25,528,353	89,155	70,065	13,656	777,016	949,892
Jun-22	2,500,572	1,696,529	561,051	17,974,611	22,732,764	93,944	85,186	10,413	750,248	939,791
Jul-22	3,282,550	1,827,083	751,584	20,515,964	26,377,181	123,558	113,628	21,662	983,254	1,242,102
Aug-22	3,503,673	2,674,684	1,672,114	28,195,238	36,045,709	180,383	120,951	24,972	1,268,015	1,594,321
Sep-22	5,049,466	3,491,630	1,876,871	24,187,990	34,605,956	233,423	116,138	30,529	1,236,193	1,616,283
Oct-22	5,904,475	2,655,272	955,026	30,628,106	40,142,879	228,390	138,991	46,401	1,250,429	1,664,211
Nov-22	5,708,367	2,965,064	517,645	44,237,173	53,428,249	224,222	152,100	33,565	1,488,793	1,898,680
Dec-22	6,170,341	3,291,381	552,227	51,135,266	61,149,215	239,984	188,033	29,565	1,623,366	2,080,948
Jan-23	6,515,957	4,314,796	850,805	39,738,417	51,419,976	270,895	182,865	34,331	1,387,946	1,876,037
Feb-23	7,215,352	5,071,691	1,217,385	45,105,924	58,610,353	326,899	216,275	53,435	1,524,379	2,120,988
Mar-23	9,550,152	4,583,157	1,057,679	70,598,385	85,789,373	443,863	240,439	56,522	2,188,422	2,929,246
TOTAL	70,618,437	44,255,159	12,420,851	463,895,013	591,189,459	2,894,729	2,151,080	420,634	17,386,867	22,853,310

	Cleared MW					Cleared Volume				
Month	Import	Export	Wheel	Internal	Total	Import	Export	Wheel	Internal	Total
Jan-22	646,722	767,142	117,381	4,620,298	6,151,542	36,367	43,966	5,426	270,206	355,965
Feb-22	691,238	1,223,319	158,192	5,929,560	8,002,309	36,599	70,794	8,868	308,327	424,588
Mar-22	1,329,615	780,044	201,988	5,802,984	8,114,631	35,389	70,114	7,272	274,549	387,324
Apr-22	725,227	350,854	119,726	5,305,536	6,501,343	34,010	31,635	3,574	247,502	316,721
May-22	639,846	382,771	142,568	5,245,037	6,410,221	27,860	26,912	6,371	265,029	326,172
Jun-22	669,243	624,991	186,867	5,872,139	7,353,240	33,262	37,959	4,774	298,574	374,569
Jul-22	765,389	695,229	310,774	6,419,096	8,190,488	42,766	44,961	9,846	366,582	464,155
Aug-22	753,371	1,048,871	924,161	8,438,635	11,165,039	58,186	51,088	10,690	442,817	562,781
Sep-22	1,308,969	836,935	445,823	6,954,810	9,546,538	94,683	48,744	8,853	461,842	614,122
Oct-22	971,339	898,627	264,771	8,830,299	10,965,036	49,875	56,411	12,507	430,700	549,493
Nov-22	1,020,080	915,121	129,612	13,641,487	15,706,300	52,461	58,849	6,480	523,514	641,304
Dec-22	1,091,973	1,100,739	153,882	15,523,453	17,870,046	62,283	77,664	9,222	595,117	744,286
Jan-23	993,294	1,664,192	343,642	14,637,453	17,638,580	59,612	81,602	11,202	555,954	708,370
Feb-23	910,934	1,624,120	314,922	13,440,920	16,290,896	64,844	76,998	10,795	521,469	674,106
Mar-23	946,995	836,769	139,944	16,527,618	18,451,326	68,545	56,128	8,141	581,143	713,957
TOTAL	13,464,236	13,749,723	3,954,252	137,189,325	168,357,536	756,742	833,825	124,021	6,143,325	7,857,913

In the first three months of 2023, the cleared MW volume of up to congestion transactions was comprised of 5.4 percent imports, 7.9 percent exports, 1.5 percent wheeling transactions and 85.2 percent internal transactions. Less than 0.1 percent of the up to congestion transactions had matching real-time energy market transactions.

Sham Scheduling

Sham scheduling refers to a scheduling method under which a market participant breaks a single transaction, from generation balancing authority (source) to load balancing authority (sink), into multiple segments. Sham scheduling hides the actual source of generation from the load balancing authority. When unable to identify the source of the energy, the load balancing authority cannot see how the power will flow to the load, which can create loop flows and result in inaccurate pricing for transactions.

For example, if the generation balancing authority (source) is NYISO, and the load balancing authority (sink) is PJM, the transaction would be priced, in the PJM energy market, at the PJM/NYIS Interface regardless of the submitted path. However, if a market participant were to break the transaction into multiple segments, one on the NYIS-ONT path, and a second segment on the ONT-MISO-PJM path, the market participant would conceal the true source (NYISO) from PJM, and PJM would price the transaction as if its source were Ontario (the ONT interface price).

Sham scheduling can also be achieved by submitting a transaction that is in the opposite direction of a portion of a larger transaction schedule.

For example, market participants can submit one transaction with multiple segments among balancing authorities and another transaction which offsets all or part of a segment of the first transaction. If a market participant submits two separate transactions, one on the ONT-MISO-PJM path, and a second on the PJM-MISO path, the result of these transactions would be a net scheduled transaction from ONT to MISO, as the MISO-PJM segment of the first transaction is offset by the PJM-MISO transaction. In this example, PJM is not required to raise or lower generation as a result of these transactions, as they would for an import or an export, and there are no associated power flows across PJM. Nonetheless, the market participant is paid the price difference between the PJM/ONT interface pricing point and the PJM/MISO interface pricing point. The market participant would be paid the PJM/ONT interface pricing point for the first transaction (ONT to PJM import) and the market participant would pay the PJM/MISO interface pricing point for the second transaction (PJM to MISO export). If the PJM/ONT interface price were higher than the PJM/MISO interface price, the market participant would be paid a net profit from the PJM market even though there was no impact on PJM operations.

At the April 10, 2013, PJM Market Implementation Committee (MIC), the MMU presented a problem statement and issue charge to address sham scheduling activities.[63] The expected deliverables from the stakeholder meetings were revisions to the Tariff and PJM business manuals. The topic was discussed at several MIC meetings. While there was stakeholder agreement that sham scheduling activity was inappropriate, consensus on revised tariff and manual language was not achieved. The topic was closed. The MMU clarified that it would continue to monitor transactions for sham scheduling activities and that the MMU could refer market participants for sham scheduling activities.

The MMU monitors for sham scheduling activities on a daily basis. Following the stakeholder discussions in 2013, the net profits obtained from sham scheduling activities fell by 114.8 percent, from net profits of $15.5 million in 2014, to a net loss of $2.3 million in 2022. The total number of hours of sham scheduling segments where the MW profile matched exactly across all segments of the path combinations in the same hour fell by 85.6 percent, from 1,898 hours in 2014 to 273 hours in 2022.

The MMU recommends that PJM implement rules to prevent sham scheduling. The MMU recommends that PJM apply after the fact market settlement adjustments to identified sham scheduling segments to ensure that market participants cannot benefit from sham scheduling.

Elimination of Ontario Interface Pricing Point

The PJM/IMO interface pricing point (Ontario) was created to reflect the fact that transactions that originate or sink in the IESO balancing authority create actual energy flows that are split between the MISO and NYISO interface pricing points. PJM created the PJM/IMO interface pricing point to reflect the

63 *See* Market Path/Interface Pricing Point alignment Problem Statement, at: <http://www.monitoringanalytics.com/reports/Presentations/2013/IMM_MIC_Market_Path_Interface_Pricing_Point_Alignment_Problem_Statement_201304010.pdf>.

actual power flows across both the MISO/PJM and NYISO/PJM Interfaces. The IMO does not have physical ties with PJM because it is not contiguous.

Prior to June 1, 2015, the PJM/IMO interface pricing point was defined as the LMP at the IESO Bruce bus. The LMP at the Bruce bus includes a congestion and loss component across the MISO and NYISO balancing authorities.

The noncontiguous nature of the PJM/IMO interface pricing point creates opportunities for market participants to engage in sham scheduling activities.[64] For example, a market participant can use two separate transactions to create a flow from Ontario to MISO. In this example, the market participant uses the PJM energy market as a temporary generation and load point by first submitting a wheeling transaction from Ontario, through MISO and into PJM, then by submitting a second transaction from PJM to MISO. These two transactions, combined, create an actual flow along the Ontario/MISO Interface. Through sham scheduling, the market participant receives settlements from PJM when no changes in generation occur. This activity is similar to that observed when PJM had a Southwest and Southeast interface pricing point. During that time, market participants would use the PJM spot market as a temporary load and generation point to wheel transactions through the PJM energy market. This was done to take advantage of the price differences between the interfaces without providing the market benefits of congestion relief.

A new PJM/IMO interface price method was implemented on June 1, 2015. The new method uses a dynamic weighting of the PJM/MISO interface price and the PJM/NYIS interface price, based on the performance of the Michigan-Ontario PARs. When the absolute value of the actual flows on the PARs are greater than or equal to the absolute value of the scheduled flows on the PARs, and the scheduled and actual flows are in the same direction, the PJM/IMO interface price will be equal to the PJM/MISO interface price (i.e. 100 percent weighting on the PJM/MISO Interface). When actual flows on the PARs are in the opposite direction of the scheduled flows on the PARs, the PJM/IMO interface price will be equal to the PJM/NYIS interface price (i.e. 100 percent weighting on the PJM/NYIS Interface). When the absolute value of the actual flows on the PARs are less than or equal to the absolute value of the scheduled flows on the PARs, and the scheduled and actual flows are in the same direction, the PJM/IMO interface price will be a combination to the PJM/MISO interface price and the PJM/NYIS interface price. In this case the weightings of the PJM/MISO and PJM/NYIS interface prices are determined based on the scheduled and actual flows. For example, in a given interval, the scheduled flow on the Michigan-Ontario PARs is 1,000 MW, and the actual flow is 800 MW. If in that same interval, the PJM/MISO interface price is $45.00 and the PJM/NYIS interface price $30.00, the PJM/IMO interface price would be calculated with a weighting of 80 percent of the PJM/MISO interface price ($45.00 * 0.8, or $36.00) and 20 percent of the PJM/NYIS interface price ($30.00 * 0.2, or $6.00), for a PJM/IMO interface price of $42.00.

The MMU believes that the new PJM/IMO interface price method is a step in the right direction towards pricing energy that sources or sinks in Ontario based on the path of the actual, physical transfer of energy. The MMU remains concerned about the assumption of PAR operations, and will continue to evaluate the impact of PARs on the scheduled and actual flows and the impacts on the PJM/IMO interface price. The MMU remains concerned about the potential for market participants to continue to engage in sham scheduling activities after the new method is implemented.

The MMU recommends that if the PJM/IMO interface price remains and with PJM's new method in place, that PJM implement additional business rules to remove the incentive to engage in sham scheduling activities using the PJM/IMO interface price. Such rules would prohibit the same market participant from scheduling an export transaction from PJM to any balancing authority while at the same time an import transaction is scheduled to PJM that receives the PJM/IMO interface price. PJM should also prohibit the same market participant from scheduling an import transaction to PJM from any balancing authority while at the same time an export transaction is scheduled from PJM that receives the PJM/IMO interface price.

In the first three months of 2023, of the 219.6 GWh of gross scheduled transactions between PJM and IESO, 218.5 GWh (99.5 percent) wheeled through MISO (Table 9-25). The MMU recommends that PJM eliminate the PJM/IMO interface pricing point, and assign the transactions that originate

64 *See* "Sham Scheduling," Presented at the PJM Market Monitoring Unit Advisory Committee (MMUAC) meeting held on December 6, 2013 <http://www.monitoringanalytics.com/reports/Presentations/2013/IMM_Sham_Scheduling_20131206.pdf>.

or sink in the IESO balancing authority to the PJM/MISO interface pricing point.[65]

PJM and NYISO Coordinated Interchange Transactions

Coordinated transaction scheduling (CTS) provides the option for market participants to submit intra-hour transactions between the NYISO and PJM that include an interface spread bid on which transactions are evaluated.[66] The evaluation is based on the forward-looking prices as determined by PJM's intermediate term security constrained economic dispatch tool (IT SCED) and the NYISO's real-time commitment (RTC) tool. PJM shares its PJM/NYISO interface price IT SCED results with the NYISO. The NYISO compares the PJM/NYISO interface price with its RTC calculated NYISO/PJM interface price. If the PJM and NYISO interface price spread is greater than the market participant's CTS bid, the transaction is approved. If the PJM and NYISO interface price spread is less than the CTS bid, the transaction is denied.

The IT SCED application runs every five minutes and each run produces forecast LMPs for the intervals approximately 30 minutes, 45 minutes, 90 minutes and 135 minutes ahead. Therefore, for each 15 minute interval, the various IT SCED solutions will produce 12 forecasted PJM/NYIS interface prices. To evaluate the accuracy of IT SCED forecasts, the forecasted PJM/NYIS interface price for each 15 minute interval from IT SCED was compared to the actual real-time interface LMP for the first three months of 2023. Table 9-42 shows that over all 12 forecast ranges, IT SCED predicted the real-time PJM/NYIS interface LMP within the range of $0.00 to $5.00 in 40.3 percent of the intervals. In those intervals, the average price difference between the IT SCED forecasted LMP and the actual real-time LMP was $1.95 per MWh. In 5.9 percent of all intervals, the absolute value of the average price difference between the IT SCED forecasted LMP and the actual real-time interface LMP was greater than $20.00. The average price differences were $54.40 when the price difference was greater than $20.00, and $87.40 when the price difference was greater than -$20.00.

Table 9-42 Differences between forecast and actual PJM/NYIS interface prices: January through March, 2023

Range of Price Differences	Percent of All Intervals	Average Price Difference
> $20	3.5%	$54.40
$10 to $20	5.1%	$13.59
$5 to $10	10.9%	$6.98
$0 to $5	40.3%	$1.95
$0 to -$5	30.0%	$1.71
-$5 to -$10	5.4%	$6.97
-$10 to -$20	2.4%	$14.02
< -$20	2.4%	$87.40

Table 9-43 shows how the accuracy of the IT SCED forecasted LMPs changes as the cases approach real-time. In the final IT SCED results prior to real time, in 63.2 percent of all intervals, the average price difference between the IT SCED forecasted LMP and the actual real-time interface LMP fell within +/- $5.00 of the actual PJM/NYIS interface real-time LMP, compared to 69.6 percent in the 135 minute ahead IT SCED results.

Table 9-43 Differences between forecast and actual PJM/NYIS interface prices: January through March, 2023

	~ 135 Minutes Prior to Real-Time		~ 90 Minutes Prior to Real-Time		~ 45 Minutes Prior to Real-Time		~ 30 Minutes Prior to Real-Time	
Range of Price Differences	Percent of Intervals	Average Price Difference	Percent of Intervals	Average Price Difference	Percent of Intervals	Average Price Difference	Percent of Intervals	Average Price Difference
> $20	5.7%	$63.34	2.0%	$42.21	1.2%	$44.37	5.7%	$58.90
$10 to $20	6.0%	$13.72	4.3%	$13.42	3.6%	$13.28	6.7%	$13.72
$5 to $10	10.9%	$6.98	10.3%	$6.95	8.7%	$6.97	13.6%	$7.02
$0 to $5	41.5%	$1.86	43.1%	$1.92	37.0%	$1.91	36.8%	$2.16
$0 to -$5	28.1%	$1.56	30.4%	$1.62	36.5%	$1.88	26.4%	$1.84
-$5 to -$10	4.0%	$6.84	5.0%	$6.81	7.1%	$7.05	5.8%	$7.08
-$10 to -$20	1.7%	$13.91	2.4%	$14.03	3.1%	$13.77	2.5%	$14.08
< -$20	2.0%	$95.75	2.5%	$87.80	2.9%	$80.46	2.5%	$86.07

In 8.2 percent of the intervals in the 30 minute ahead forecast, the absolute value of the average price difference between the IT SCED forecasted LMP and the actual real-time interface LMP was greater than $20.00. The average price

65 On October 1, 2013, a sub-group of PJM's Market Implementation Committee started stakeholder discussions to address this inconsistency in market pricing.

66 PJM and the NYISO implemented CTS on November 4, 2014. 146 FERC ¶ 61,096 (2014).

difference was $58.90 when the price difference was greater than $20.00, and $86.07 when the price difference was greater than -$20.00.

Table 9-44 and Table 9-45 show the monthly differences between forecasted and actual PJM/NYIS interface prices. Analysis of the data on a monthly basis shows that there is a decline in the accuracy of the IT SCED forecast during periods of cold and hot weather.

Table 9-44 Monthly Differences between forecast and actual PJM/NYIS interface prices (percent of intervals): January through March, 2023

Interval	Range of Price Differences	Jan	Feb	Mar	YTD Avg
~ 30 Minutes Prior to Real-Time	> $20	6.3%	8.1%	3.0%	5.7%
	$10 to $20	7.4%	6.1%	6.4%	6.7%
	$5 to $10	14.6%	11.2%	14.6%	13.6%
	$0 to $5	31.5%	36.5%	42.3%	36.8%
	$0 to -$5	28.9%	27.0%	23.3%	26.4%
	-$5 to -$10	6.3%	5.5%	5.7%	5.8%
	-$10 to -$20	2.4%	2.8%	2.5%	2.5%
	< -$20	2.7%	2.7%	2.1%	2.5%
Interval	Range of Price Differences	Jan	Feb	Mar	YTD Avg
~ 45 Minutes Prior to Real-Time	> $20	1.3%	1.3%	1.0%	1.2%
	$10 to $20	4.0%	3.2%	3.3%	3.6%
	$5 to $10	9.4%	7.2%	9.4%	8.7%
	$0 to $5	31.8%	37.6%	41.6%	37.0%
	$0 to -$5	39.5%	37.2%	32.8%	36.5%
	-$5 to -$10	7.6%	7.0%	6.7%	7.1%
	-$10 to -$20	3.1%	3.5%	2.9%	3.1%
	< -$20	3.2%	3.0%	2.4%	2.9%
Interval	Range of Price Differences	Jan	Feb	Mar	YTD Avg
~ 90 Minutes Prior to Real-Time	> $20	2.0%	2.3%	1.6%	2.0%
	$10 to $20	5.3%	3.9%	3.8%	4.3%
	$5 to $10	10.6%	8.6%	11.6%	10.3%
	$0 to $5	36.4%	43.9%	49.0%	43.1%
	$0 to -$5	34.7%	30.7%	25.9%	30.4%
	-$5 to -$10	5.7%	5.3%	4.1%	5.0%
	-$10 to -$20	2.5%	2.6%	2.1%	2.4%
	< -$20	2.9%	2.6%	1.9%	2.5%
Interval	Range of Price Differences	Jan	Feb	Mar	YTD Avg
~ 135 Minutes Prior to Real-Time	> $20	5.9%	4.8%	6.3%	5.7%
	$10 to $20	6.8%	4.9%	6.3%	6.0%
	$5 to $10	10.7%	10.1%	11.9%	10.9%
	$0 to $5	35.0%	42.7%	46.9%	41.5%
	$0 to -$5	32.4%	29.2%	22.9%	28.1%
	-$5 to -$10	4.7%	4.4%	3.0%	4.0%
	-$10 to -$20	2.2%	1.7%	1.2%	1.7%
	< -$20	2.3%	2.3%	1.6%	2.0%

Table 9-45 Monthly differences between forecast and actual PJM/NYIS interface prices (average price difference): January through March, 2023

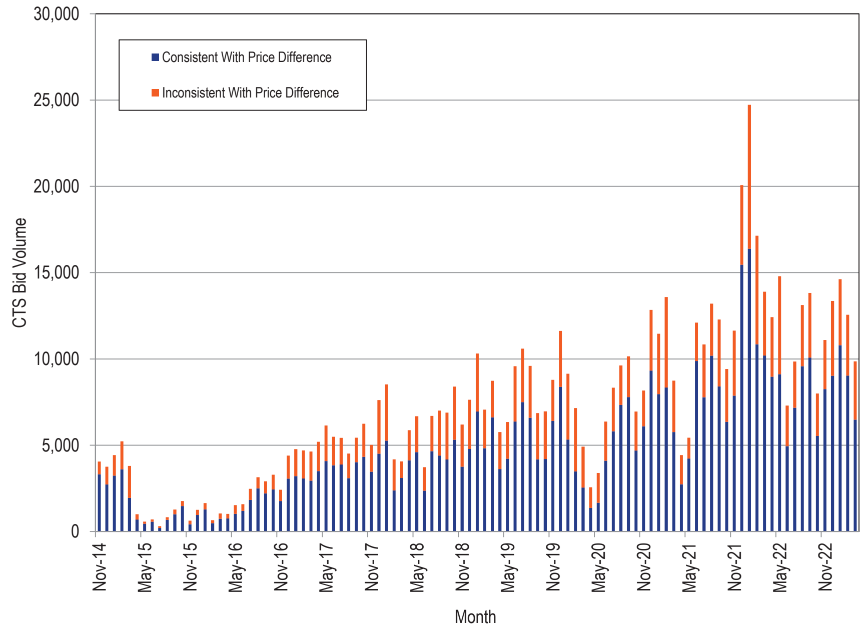
Interval	Range of Price Differences	Jan	Feb	Mar	YTD Avg
~ 30 Minutes Prior to Real-Time	> $20	$42.99	$79.53	$42.70	$58.90
	$10 to $20	$13.65	$13.80	$13.74	$13.72
	$5 to $10	$7.03	$6.97	$7.05	$7.02
	$0 to $5	$2.24	$2.11	$2.14	$2.16
	$0 to -$5	$1.89	$1.86	$1.76	$1.84
	-$5 to -$10	$7.01	$7.02	$7.20	$7.08
	-$10 to -$20	$14.55	$13.48	$14.23	$14.08
	< -$20	$107.40	$83.71	$61.28	$86.07
Interval	Range of Price Differences	Jan	Feb	Mar	YTD Avg
~ 45 Minutes Prior to Real-Time	> $20	$28.77	$68.93	$36.25	$44.37
	$10 to $20	$13.51	$13.04	$13.20	$13.28
	$5 to $10	$7.07	$6.96	$6.87	$6.97
	$0 to $5	$1.93	$1.91	$1.89	$1.91
	$0 to -$5	$2.01	$1.79	$1.80	$1.88
	-$5 to -$10	$6.96	$7.05	$7.14	$7.05
	-$10 to -$20	$14.06	$13.49	$13.77	$13.77
	< -$20	$95.07	$83.53	$57.40	$80.46
Interval	Range of Price Differences	Jan	Feb	Mar	YTD Avg
~ 90 Minutes Prior to Real-Time	> $20	$40.57	$49.27	$35.07	$42.21
	$10 to $20	$13.38	$13.69	$13.21	$13.42
	$5 to $10	$7.00	$6.75	$7.04	$6.95
	$0 to $5	$1.92	$1.85	$1.96	$1.92
	$0 to -$5	$1.71	$1.59	$1.54	$1.62
	-$5 to -$10	$6.76	$6.67	$7.04	$6.81
	-$10 to -$20	$14.46	$13.38	$14.27	$14.03
	< -$20	$100.84	$90.08	$64.93	$87.80
Interval	Range of Price Differences	Jan	Feb	Mar	YTD Avg
~ 135 Minutes Prior to Real-Time	> $20	$72.27	$55.52	$60.25	$63.34
	$10 to $20	$13.91	$13.67	$13.55	$13.72
	$5 to $10	$6.98	$6.89	$7.05	$6.98
	$0 to $5	$1.89	$1.77	$1.92	$1.86
	$0 to -$5	$1.62	$1.53	$1.51	$1.56
	-$5 to -$10	$6.84	$6.81	$6.88	$6.84
	-$10 to -$20	$14.18	$14.11	$13.18	$13.91
	< -$20	$115.89	$96.18	$66.06	$95.75

The NYISO uses PJM's IT SCED forecasted LMPs to compare against the NYISO Real-Time Commitment (RTC) results in its evaluation of CTS transactions. The NYISO approves CTS (spread bid) transactions when the offered spread is less than or equal to the spread between the IT SCED forecast PJM/NYIS interface LMP and the NYISO RTC forecast NYIS/PJM interface LMP. The large differences between forecast and actual LMPs in the intervals closest to real-time could cause CTS transactions to be approved that would contribute to transactions being scheduled counter to real-time economic signals, and contribute to inefficient scheduling across the PJM/NYIS border.

CTS transactions are evaluated based on the spread bid, which limits the amount of price convergence that can occur. As long as balancing operating reserve charges are applied and CTS transactions are optional, the CTS proposal represents a small incremental step toward better interface pricing. The NYISO has a 75 minute bid submission deadline. While market participants have the option to specify bid data on 15 minute intervals, market participants must submit their bids 75 minutes prior to the requested transaction start time. The 75 minute bid submission deadline associated with scheduling energy transactions in the NYISO should be shortened. Reducing this deadline could significantly improve pricing efficiency at the PJM/NYISO border for non-CTS transactions and for CTS transactions as market participants would be able to adjust their bids in response to real-time price signals.

CTS transactions were evaluated for each 15 minute interval. From November 4, 2014, through March 31, 2023, 718,568 15 minute CTS schedules were approved through the CTS process based on the forecast LMPs. When the forecast LMPs for the approved intervals were compared to the hourly integrated real-time LMPs, the direction of the flow in 224,247 (31.2 percent) of the intervals was inconsistent with the differences in real-time PJM/NYISO and NYISO/PJM prices. For example, if a market participant submits a CTS transaction from NYISO to PJM with a spread bid of $5.00, and NYISO's forecasted PJM interface price was at least $5.00 lower than PJM's forecasted NYISO interface price, the transaction would be approved. For 31.2 percent of the approved transactions, the actual, real-time price differentials were in the opposite direction of the forecast differential. The actual, real-time price differentials meant that the transactions would have been economic in the opposite direction. For 68.8 percent of the intervals, the forecast price differentials were consistent with real-time PJM/NYISO and NYISO/PJM price differences. Figure 9-20 shows the monthly volume of cleared PJM/NYIS CTS bids. Figure 9-20 also shows the percent of cleared bids that resulted in flows consistent and inconsistent with price differences.

Figure 9-20 Monthly cleared PJM/NYIS CTS bid volume: November 4, 2014 through March 31, 2023



The data reviewed show that IT SCED is not a highly accurate predictor of the real-time PJM/NYIS interface prices. This limits the effectiveness of CTS in improving interface pricing between PJM and NYISO.

Reserving Ramp on the PJM/NYISO Interface

Prior to the implementation of CTS, PJM held ramp space for all transactions submitted between PJM and the NYISO as soon as the NERC Tag was approved. At that time, once transactions were evaluated by the NYISO through their real-time market clearing process, any adjustments made to the submitted transactions would be reflected on the NERC Tags and the PJM ramp was adjusted accordingly.

As part of this process, PJM was often required to make adjustments to transactions on its other interfaces in order to bring total system ramp back to within its limit. The default ramp limit in PJM is +/- 1,000 MW. For example, the ramp in a given interval is currently -1,000 MW, consisting of 2,000 MW of imports from the NYISO to PJM and 3,000 MW of exports from PJM on its other interfaces. If, through the NYISO real-time market clearing process, the NYISO only approves 1,000 MW of the imports, the other 1,000 MW of import transactions from the NYISO would be curtailed. The ramp in this interval would then be -2,000 MW, consisting of the 1,000 MW of cleared imports from the NYISO to PJM and 3,000 MW of exports from PJM on its other interfaces. PJM would then be required to curtail an additional 1,000 MW of exports at its other interface to bring the limit back to within +/- 1,000. These curtailments were made on a last in first out basis as determined by the timestamp on the NERC Tag.

With the implementation of the CTS product with the NYISO, PJM modified how ramp is handled at the PJM/NYISO Interface. Effective November 4, 2014, PJM no longer holds ramp room for any transactions submitted between PJM and the NYISO at the time of submission. Only after the NYISO completes its real-time market clearing process, and communicates the results to PJM, does PJM perform a ramp evaluation on transactions scheduled with the NYISO. If, in the event the NYISO market clearing process would violate ramp, PJM would make additional adjustments based on a last-in first-out basis as determined by the timestamp on the NERC Tag. This process prevents the transactions scheduled at the PJM/NYISO Interface from holding (or creating) ramp until NYISO has completed its economic evaluation and the transactions are approved through the NYISO market clearing process.

PJM and MISO Coordinated Interchange Transaction Proposal

PJM and MISO proposed the implementation of coordinated interchange transactions, similar to the PJM/NYISO approach, through the Joint and Common Market Initiative. The PJM/MISO coordinated transaction scheduling (CTS) process provides the option for market participants to submit intra-hour transactions between the MISO and PJM that include an interface spread bid on which transactions are evaluated. Similar to the PJM/NYISO approach, the evaluation is based, in part, on the forward-looking prices as determined by PJM's intermediate term security constrained economic dispatch tool (IT SCED). Unlike the PJM/NYISO CTS process in which the NYISO performs the evaluation, the PJM/MISO CTS process uses a joint clearing process in which both RTOs share forward looking prices. On October 3, 2017, PJM and MISO implemented the CTS process.

The IT SCED application runs every five minutes and each run produces forecast LMPs for the intervals approximately 30 minutes, 45 minutes, 90 minutes and 135 minutes ahead. Therefore, for each 15 minute interval, the various IT SCED solutions will produce 12 forecasted PJM/MISO interface prices. To evaluate the accuracy of IT SCED forecasts, the forecasted PJM/MISO interface price for each 15 minute interval from IT SCED was compared to the actual real-time interface LMP for the first three months of 2023. Table 9-46 shows that over all 12 forecast ranges, IT SCED predicted the real-time PJM/MISO interface LMP within the range of $0.00 to $5.00 in 39.2 percent of all intervals. In those intervals, the average price difference between the IT SCED forecasted LMP and the actual real-time LMP was $2.02. In 6.9 percent of all intervals, the absolute value of the average price difference between the IT SCED forecasted LMP and the actual real-time interface LMP was greater than $20.00. The average price differences were $48.11 when the price difference was greater than $20.00, and $71.04 when the price difference was greater than -$20.00.

Table 9-46 Differences between forecast and actual PJM/MISO interface prices: January through March, 2023

Range of Price Differences	Percent of All Intervals	Average Price Difference
> $20	4.3%	$48.11
$10 to $20	6.2%	$13.75
$5 to $10	12.6%	$7.04
$0 to $5	39.2%	$2.02
$0 to -$5	27.5%	$1.70
-$5 to -$10	4.9%	$6.96
-$10 to -$20	2.7%	$14.42
< -$20	2.6%	$71.04

Table 9-47 shows how the accuracy of the IT SCED forecasted LMPs change as the cases approach real-time. In the final IT SCED results prior to real-time, in 63.5 percent of all intervals, the average price difference between the IT SCED forecasted LMP and the actual real-time interface LMP fell within +/- $5.00 of the actual PJM/MISO interface real-time LMP, compared to 64.7 percent in the 135 minute ahead IT SCED results.

Table 9-47 Differences between forecast and actual PJM/MISO interface prices: January through March, 2023

	~ 135 Minutes Prior to Real-Time		~ 90 Minutes Prior to Real-Time		~ 45 Minutes Prior to Real-Time		~ 30 Minutes Prior to Real-Time	
Range of Price Differences	Percent of Intervals	Average Price Difference	Percent of Intervals	Average Price Difference	Percent of Intervals	Average Price Difference	Percent of Intervals	Average Price Difference
> $20	7.6%	$64.89	3.4%	$38.11	2.5%	$41.39	4.6%	$38.06
$10 to $20	7.1%	$13.93	5.4%	$13.53	5.6%	$13.69	7.2%	$13.81
$5 to $10	12.2%	$7.09	12.2%	$6.97	11.4%	$7.02	13.5%	$7.11
$0 to $5	39.4%	$1.95	41.9%	$1.98	37.3%	$2.02	35.9%	$2.13
$0 to -$5	25.4%	$1.55	27.0%	$1.64	31.5%	$1.82	27.6%	$1.84
-$5 to -$10	3.9%	$6.87	4.8%	$6.97	6.1%	$6.97	5.4%	$6.97
-$10 to -$20	2.2%	$14.42	2.7%	$14.41	2.9%	$14.43	3.0%	$14.53
< -$20	2.1%	$75.87	2.6%	$70.37	2.8%	$69.17	2.7%	$69.10

In 7.3 percent of the intervals in the 30 minute ahead forecast, the absolute value of the average price difference between the IT SCED forecasted LMP and the actual real-time interface LMP was greater than $20.00, the average price differences were $38.06 when the price difference was greater than $20.00, and $69.10 when the price difference was greater than -$20.00.

Table 9-48 and Table 9-49 show the monthly differences between forecasted and actual PJM/MISO interface prices. Analysis of the data on a monthly basis shows that there is a decline in the accuracy of the IT SCED forecast during periods of cold and hot weather.

Table 9-48 Monthly differences between forecast and actual PJM/MISO interface prices (percent of intervals): January through March, 2023

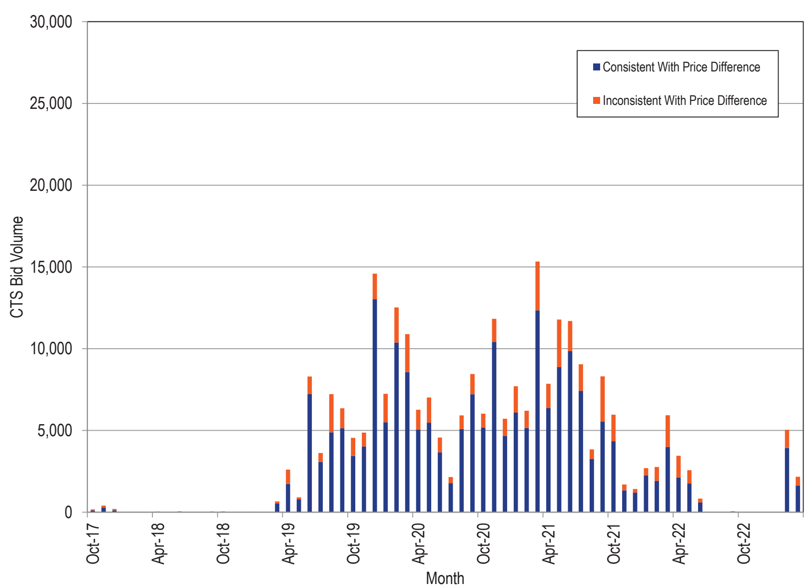
Interval	Range of Price Differences	Jan	Feb	Mar	YTD Avg
~ 30 Minutes Prior to Real-Time	> $20	7.8%	2.0%	3.9%	4.6%
	$10 to $20	6.0%	8.5%	7.1%	7.2%
	$5 to $10	13.4%	13.1%	14.1%	13.5%
	$0 to $5	29.3%	37.5%	41.0%	35.9%
	$0 to -$5	30.5%	29.5%	22.9%	27.6%
	-$5 to -$10	6.3%	4.6%	5.3%	5.4%
	-$10 to -$20	3.7%	2.5%	2.7%	3.0%
	< -$20	2.8%	2.2%	3.0%	2.7%
Interval	Range of Price Differences	Jan	Feb	Mar	YTD Avg
~ 45 Minutes Prior to Real-Time	> $20	3.8%	0.9%	2.5%	2.5%
	$10 to $20	6.0%	5.3%	5.4%	5.6%
	$5 to $10	10.7%	10.6%	13.0%	11.4%
	$0 to $5	33.1%	37.7%	41.1%	37.3%
	$0 to -$5	33.1%	35.1%	26.6%	31.5%
	-$5 to -$10	6.7%	5.8%	5.7%	6.1%
	-$10 to -$20	3.6%	2.4%	2.7%	2.9%
	< -$20	3.0%	2.2%	3.1%	2.8%
Interval	Range of Price Differences	Jan	Feb	Mar	YTD Avg
~ 90 Minutes Prior to Real-Time	> $20	3.9%	2.6%	3.6%	3.4%
	$10 to $20	6.0%	4.4%	5.5%	5.4%
	$5 to $10	12.0%	9.9%	14.6%	12.2%
	$0 to $5	36.2%	44.8%	45.1%	41.9%
	$0 to -$5	29.6%	30.0%	21.6%	27.0%
	-$5 to -$10	5.9%	4.1%	4.2%	4.8%
	-$10 to -$20	3.6%	2.1%	2.3%	2.7%
	< -$20	2.7%	2.1%	3.1%	2.6%
Interval	Range of Price Differences	Jan	Feb	Mar	YTD Avg
~ 135 Minutes Prior to Real-Time	> $20	8.8%	5.5%	8.4%	7.6%
	$10 to $20	7.7%	6.0%	7.5%	7.1%
	$5 to $10	11.0%	10.8%	14.8%	12.2%
	$0 to $5	34.1%	42.8%	41.6%	39.4%
	$0 to -$5	27.9%	28.3%	20.1%	25.4%
	-$5 to -$10	5.1%	3.3%	3.3%	3.9%
	-$10 to -$20	3.3%	1.6%	1.8%	2.2%
	< -$20	2.2%	1.8%	2.4%	2.1%

Table 9-49 Monthly differences between forecast and actual PJM/MISO interface prices (average price difference): January through March, 2023

Interval	Range of Price Differences	Jan	Feb	Mar	YTD Avg
~ 30 Minutes Prior to Real-Time	> $20	$36.30	$28.69	$45.83	$38.06
	$10 to $20	$13.82	$13.85	$13.74	$13.81
	$5 to $10	$7.03	$7.17	$7.14	$7.11
	$0 to $5	$2.16	$2.06	$2.16	$2.13
	$0 to -$5	$1.97	$1.78	$1.74	$1.84
	-$5 to -$10	$6.89	$7.13	$6.95	$6.97
	-$10 to -$20	$14.29	$14.57	$14.84	$14.53
	< -$20	$92.68	$44.17	$63.45	$69.10
Interval	Range of Price Differences	Jan	Feb	Mar	YTD Avg
~ 45 Minutes Prior to Real-Time	> $20	$32.53	$27.01	$59.70	$41.39
	$10 to $20	$13.99	$13.62	$13.43	$13.69
	$5 to $10	$7.00	$7.06	$7.02	$7.02
	$0 to $5	$2.06	$1.93	$2.07	$2.02
	$0 to -$5	$2.02	$1.67	$1.74	$1.82
	-$5 to -$10	$7.11	$6.89	$6.89	$6.97
	-$10 to -$20	$14.90	$14.04	$14.11	$14.43
	< -$20	$90.25	$43.91	$64.98	$69.17
Interval	Range of Price Differences	Jan	Feb	Mar	YTD Avg
~ 90 Minutes Prior to Real-Time	> $20	$32.57	$27.62	$51.02	$38.11
	$10 to $20	$13.99	$13.22	$13.25	$13.53
	$5 to $10	$7.08	$6.85	$6.96	$6.97
	$0 to $5	$2.02	$1.90	$2.02	$1.98
	$0 to -$5	$1.65	$1.64	$1.63	$1.64
	-$5 to -$10	$6.95	$6.91	$7.05	$6.97
	-$10 to -$20	$14.78	$13.95	$14.22	$14.41
	< -$20	$95.69	$43.40	$64.14	$70.37
Interval	Range of Price Differences	Jan	Feb	Mar	YTD Avg
~ 135 Minutes Prior to Real-Time	> $20	$59.33	$57.19	$75.19	$64.89
	$10 to $20	$14.70	$14.10	$13.04	$13.93
	$5 to $10	$7.22	$6.92	$7.09	$7.09
	$0 to $5	$1.94	$1.83	$2.06	$1.95
	$0 to -$5	$1.51	$1.58	$1.57	$1.55
	-$5 to -$10	$6.81	$6.93	$6.91	$6.87
	-$10 to -$20	$14.49	$14.75	$14.03	$14.42
	< -$20	$108.78	$43.39	$66.64	$75.87

CTS transactions were evaluated for each interval. From October 3, 2017, through March 31, 2023, 259,657 CTS schedules were approved through the CTS process based on the forecast LMPs. When the forecast LMPs for the approved intervals were compared to the hourly integrated real-time LMPs, the direction of the flow in 52,049 (20.0 percent) of the intervals was inconsistent with the differences in real-time PJM/MISO and MISO/PJM prices. For example, if a market participant submits a CTS transaction from MISO to PJM with a spread bid of $5.00, and MISO's forecasted PJM interface price was at least $5.00 lower than PJM's forecasted MISO interface price, the transaction would be approved. For 20.0 percent of the approved transactions, the actual, real-time price differentials were in the opposite direction of the forecast differential. The actual, real-time price differentials meant that the transactions would have been economic in the opposite direction. For 80.0 percent of the intervals, the forecast price differentials were consistent with real-time PJM/MISO and MISO/PJM price differences. Figure 9-21 shows the monthly volume of cleared PJM/MISO CTS bids. Figure 9-21 also shows the percent of cleared bids that resulted in flows consistent and inconsistent with price differences. In June 2022, MISO experienced software issues that prevented the submission and clearing of CTS transactions. The issue was resolved in August 2022. It is unclear why market participants did not resume scheduling CTS transactions at the MISO interface until February 2023.

Figure 9-21 Monthly cleared PJM/MISO CTS bid volume: October 3, 2017 through March 31, 2023



The data reviewed show that IT SCED is not a highly accurate predictor of the real-time PJM/MISO interface prices. This limits the effectiveness of CTS in improving interface pricing between PJM and MISO.

Willing to Pay Congestion and Not Willing to Pay Congestion

When reserving nonfirm transmission, market participants have the option to choose whether or not they are willing to pay congestion. When the market participant elects to pay congestion, PJM operators redispatch the system if necessary to allow the energy transaction to continue to flow. The system redispatch often creates price separation across buses on the PJM system. The difference in LMPs between two buses in PJM is the congestion cost (and losses) that the market participant pays in order for their transaction to continue to flow.

The MMU recommended that PJM modify the not willing to pay congestion product to address the issues of uncollected congestion charges. The MMU recommended charging market participants for any congestion incurred while the transaction is loaded, regardless of their election of transmission service, and restricting the use of not willing to pay congestion transactions (as well as all other real-time external energy transactions) to transactions at interfaces.

On April 12, 2011, the PJM Market Implementation Committee (MIC) endorsed the changes recommended by the MMU. The elimination of internal sources and sinks on transmission reservations addressed most of the MMU concerns, as there can no longer be uncollected congestion charges for imports to PJM or exports from PJM. There is still potential exposure to uncollected congestion charges in wheel through transactions, and the MMU will continue to evaluate if additional mitigation measures would be appropriate to address this exposure.

Table 9-50 shows that since the inception of the business rule change on April 12, 2013, there was uncollected congestion in only two months (January 2016 and February 2019). In both months, there was negative uncollected congestion. The negative congestion means that market participants who used the not willing to pay congestion transmission option for their wheel through transactions had transactions that flowed in the direction opposite to congestion. When market participants use the not willing to pay congestion product, it also means that they are not willing to receive congestion credits, which was the case in both January 2016 and February 2019.

Table 9-50 Monthly uncollected congestion charges: January 2010 through March 2023

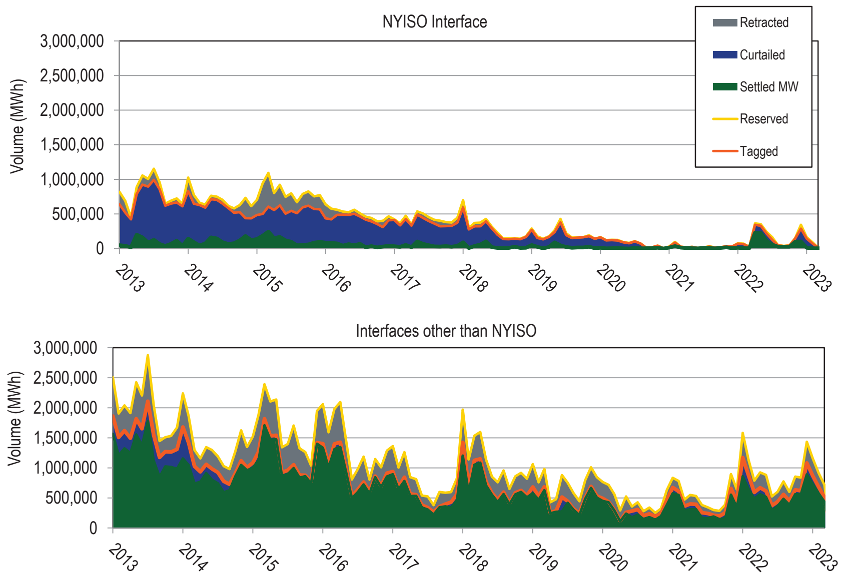
Month	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Jan	$148,764	$3,102	$0	$5	$0	$0	($44)	$0	$0	$0	$0	$0	$0	$0
Feb	$542,575	$1,567	($15)	$249	$0	$0	$0	$0	$0	($69,992)	$0	$0	$0	$0
Mar	$287,417	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Apr	$31,255	$4,767	($68)	($3,114)	$0	$0	$0	$0	$0	$0	$0	$0	$0	
May	$41,025	$0	($27)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Jun	$169,197	$1,354	$78	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Jul	$827,617	$1,115	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Aug	$731,539	$37	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Sep	$119,162	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Oct	$257,448	($31,443)	($6,870)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Nov	$30,843	($795)	($4,678)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Dec	$127,176	($659)	($209)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Total	$3,314,018	($20,955)	($11,789)	($2,860)	$0	$0	($44)	$0	$0	($69,992)	$0	$0	$0	$0

Spot Imports

Figure 9-22 shows the spot import service use for the NYISO Interface, and for all other interfaces, from January 1, 2013 through March 31, 2023. The yellow line shows the total monthly MWh of spot import service reserved and the orange line shows the total monthly MWh of tagged spot import service. The gray shaded area between the yellow and orange lines represents the MWh of retracted spot import service and may represent potential hoarding volumes. This ATC was initially reserved, but not tagged (used). It is possible that in some instances the reserved transmission consisted of the only available ATC which could have been used by another market participant had it not been reserved and not used. The blue shaded area between the orange line and green shaded area represents the MWh of curtailed transactions using spot import service. This area may also represent hoarding opportunities, particularly at the NYISO Interface. In this instance, it is possible that while the market participant reserved and scheduled the transmission, they may have submitted purposely uneconomic bids in the NYISO market so that their transaction would be curtailed, yet their transmission would not be retracted. The NYISO allows for market participants to modify their bids on an hourly basis, so these market participants can hold their transmission service and evaluate their bids hourly, while withholding the transmission from other market participants that may wish to use it. The green shaded area represents the total settled MWh of spot import service. Figure 9-22 shows that while there are proportionally fewer retracted MWh on the NYISO Interface than on all other interfaces, the NYISO has proportionally more curtailed MWh. This is a result of the NYISO market clearing process.[67]

67 See the *2018 State of the Market Report for PJM*, Volume II, Section 9, "Interchange Transactions," for a more complete discussion of the history of spot import transmission service.

Figure 9-22 Spot import service use: January 2013 through March 2023



The MMU continues to recommend that PJM permit unlimited spot market imports (as well as all nonfirm point to point willing to pay congestion imports and exports) at all PJM interfaces.

Interchange Optimization

When PJM prices are higher than prices in surrounding balancing authorities, imports will flow into PJM until the prices are approximately equal. This is an appropriate market response to price differentials. Given the nature of interface pricing and the treatment of interface transactions, it is not possible for PJM system operators to reliably predict the quantity or sustainability of such imports. The inability to predict interchange volumes creates additional challenges for PJM dispatch in trying to meet loads, especially on high load days. If all external transactions were submitted as real-time dispatchable transactions during emergency conditions, PJM would be able to include interchange transactions in its supply stack, and dispatch only enough interchange to meet the demand.

The MMU recommends that the submission deadline for real-time dispatchable transactions be modified from 1800 (EPT) on the prior day to three hours prior to the requested start time, and that the minimum duration be modified from one hour to 15 minutes.[68] These changes would give PJM a more flexible product that could be used to meet load based on economic dispatch rather than guessing the sensitivity of the transactions to price changes.

In addition to changing prices, transmission line loading relief procedures (TLRs), market participants' curtailments for economic reasons, and external balancing authority curtailments affect the duration of interchange transactions.

The MMU recommends that PJM explore an interchange optimization solution with its neighboring balancing authorities that would remove the need for market participants to schedule physical transactions across seams. Such a solution would include an optimized, but limited, joint dispatch approach that uses supply curves and treats seams between balancing authorities as constraints, similar to other constraints within an LMP market.

Interchange Cap During Emergency Conditions

An interchange cap is a limit on the level of interchange permitted for nondispatchable energy using spot import or hourly point to point transmission. An interchange cap is a nonmarket intervention which should be a temporary solution and should be replaced with a market based solution as soon as possible. Since the approval of this process on October 30, 2014, PJM has not yet needed to implement an interchange cap.

The purpose of the interchange cap is to help ensure that actual interchange more closely meets operators' expectations of interchange levels when internal PJM resources, e.g. CTs or demand response, are dispatched to meet the peak load. Once these resources have been called on, PJM must honor their minimum operating constraints regardless of whether additional interchange

68 The minimum duration for a real-time dispatchable transaction was modified to 15 minutes as per FERC Order No. 764. See *Integration of Variable Energy Resources*, Order No. 764, 139 FERC ¶ 61,246, order on reh'g, Order No. 764-A, 141 FERC ¶ 61231 (2012).

then materializes. Therefore any interchange received in excess of what was expected can have a suppressive effect on energy and reserve pricing and result in increased uplift.

PJM will notify market participants of the possible use of the interchange cap the day before. The interchange cap will be implemented for the forecasted peak and surrounding hours during emergency conditions.

The interchange cap will limit the acceptance of spot import and hourly nonfirm point to point interchange (imports and exports) not submitted as real time with price transactions once net interchange has reached the interchange cap value. Spot imports and hourly nonfirm point to point transactions submitted prior to the implementation of the interchange cap will not be limited. In addition, schedules with firm or network designated transmission service will not be limited either, regardless of whether net interchange is at or above the cap.

The calculation of the interchange cap is based on the operator expectation of interchange at the time the cap is calculated plus an additional margin. The margin is set at 700 MW, which is half of the largest contingency on the system. The additional margin also allows interchange to adjust to the loss of a unit or deviation between actual load and forecasted load. The interchange cap is based on the maximum sustainable interchange from PJM reliability studies.

45 Minute Schedule Duration Rule

PJM limits the change in interchange volumes on 15 minute intervals. These changes are referred to as ramp. The PJM ramp limit is designed to limit the change in the amount of imports or exports in each 15 minute interval to account for the physical characteristics of the generation to respond to changes in the level of imports and exports. The purpose of imposing a ramp limit is to help ensure the reliable operation of the PJM system. The 1,000 MW ramp limit per 15 minute interval was based on the availability of ramping capability by generators in the PJM system. The limit is based on the assumption that the available generation in the PJM system can only move 1,000 MW over any 15 minute period, although there is no supporting analysis. As an example of how the ramp limit works, if at 0800 (EPT) the sum of all external transactions were -3,000 MW (negative sign indicates net exporting), the limit for 0815 would be -2,000 MW to -4,000 MW. In other words, the starting or ending of transactions would be limited so that the overall change from the previous 15 minute period would not exceed 1,000 MW in either direction.

In 2008, there was an increase in 15 minute external energy transactions that caused swings in imports and exports submitted in response to intrahour LMP changes. This activity was due to market participants' ability to observe price differences between RTOs in the first third of the hour, and predict the direction of the price difference on an hourly integrated basis. Large quantities of MW would then be scheduled between the RTOs for the last 15 minute interval to capture those hourly integrated price differences with relatively little risk of prices changing. This increase in interchange on 15 minute intervals created operational control issues, and in some cases led to an increase in uplift charges due to calling on resources with minimum run times greater than 15 minutes needed to support the interchange transactions. As a result, a new business rule was proposed and approved that required all transactions to be at least 45 minutes in duration.

On June 22, 2012, FERC issued Order No. 764, which required transmission providers to give transmission customers the option to schedule transmission service at 15 minute intervals to reflect more accurate power production forecasts, load and system conditions.[69] On April 17, 2014, FERC issued its order which found that PJM's 45 minute duration rule was inconsistent with Order No. 764.[70]

PJM and the MMU issued a statement indicating ongoing concern about market participants' scheduling behavior, and a commitment to address any scheduling behavior that raises operational or market manipulation concerns.[71]

69 *Id.* at P 51.
70 See *Id.* at P 12.
71 See joint statement of PJM and the MMU re Interchange Scheduling issued July 29, 2014 <http://www.monitoringanalytics.com/reports/Market_Messages/Messages/PJM_IMM_Statement_on_Interchange_Scheduling_20140729.pdf>.

MISO Multi-Value Project Usage Rate (MUR)

MISO defines a multi-value project (MVP) to be a project which, according to MISO, enables the reliable and economic delivery of energy in support of public policy needs, provides multiple types of regional economic value or provides a combination of regional reliability and economic value.[72] On July 15, 2010, MISO submitted revisions to the MISO Tariff to implement criteria for identifying and allocating the costs of MVPs.[73] On December 16, 2010, the Commission accepted the proposed MVP charge for export and wheel-through transactions, except for transactions that sink in PJM.[74] The Commission stated that MISO had not shown that their proposal did not constitute a resumption of rate pancaking along the MISO-PJM seam. Following the December 16, 2010, Order, MISO began applying a multi-value usage rate (MUR) to monthly net actual energy withdrawals, export schedules and through schedules with the exception of transactions sinking in PJM. The MUR charge was applied to the relevant transactions in addition to the applicable transmission, ancillary service and network upgrade charges.

On June 7, 2014, the U.S. Court of Appeals for the Seventh Circuit granted a petition for review regarding the Commission's determination in the MVP Order and MVP Rehearing Order.[75] The Court ordered the Commission to consider on remand whether, in light of current conditions, what if any limitations on export pricing to PJM by MISO are justified.[76] The Seventh Circuit highlighted the fact that at the time of the Commission's decision to prohibit rate pancaking on transactions between MISO and PJM, all of MISO's transmission projects were local and provided only local benefits.[77]

On July 13, 2016, FERC issued an order permitting MISO to collect charges associated with MVPs for all transactions sinking in PJM, effective immediately.[78] The July 13th Order noted that in light of "the development of large scale wind generation capable of serving both MISO's and its neighbors' energy policy requirements in the western areas of MISO; the reported need of PJM entities to access those resources; and the reported need for MISO to build new transmission facilities to deliver the output of those resources within MISO for export… it is appropriate to allow MISO to assess the MVP usage charge for transmission service used to export to PJM just as MISO assesses the MVP usage charge for transmission service used to export energy to other regions."[79]

The policy rationale for permitting MISO to impose transmission costs on PJM market participants without clear criteria is weak and results in pancaking of rates. The impact is expected to increase.

Table 9-51 shows the projected usage rate to be collected for all wheels through and exports from MISO, including those that sink in PJM, for 2023 through 2041.[80] As shown in Table 9-4, there were 887.5 GWh of imports from MISO in the first three months of 2023. At the 2023 MUR of $1.55 per MWh, PJM market participants paid $1.4 million towards the costs of MISO's multi value projects. It is not clear whether the MUR charge has affected interchange volumes from MISO into PJM.

Table 9-51 MISO projected multi value project usage rate: 2023 through 2041

Year	Total Indicative MVP Usage Rate ($/MWh)
2023	$1.55
2024	$1.62
2025	$1.60
2026	$1.58
2027	$1.56
2028	$1.54
2029	$1.52
2030	$1.50
2031	$1.48
2032	$1.46
2033	$1.44
2034	$1.41
2035	$1.39
2036	$1.38
2037	$1.36
2038	$1.34
2039	$1.32
2040	$1.30
2041	$1.28
2042	$1.26

72 See MISO. MTEP "Multi Value Project Portfolio Analysis," <https://cdn.misoenergy.org/2011%20MVP%20Portfolio%20Analysis%20Full%20Report117059.pdf>.
73 See Midwest Independent Transmission Operator Inc. filing, Docket No. ER10-1791-000 (July 15, 2010).
74 133 FERC ¶ 61,221; *order on reh'g*, 137 FERC ¶ 61,074 (2011).
75 Illinois Commerce Commission, et al. v. FERC, 721 F.3d 764, 778–780 (7th Cir. 2013).
76 *Id.* at 780.
77 *Id.* at 779.
78 156 FERC ¶ 61,034 (2016).
79 *Id.* at P 55.
80 See MISO, "Schedule 26A Indicative Annual Charges," (May 4, 2022) <https://cdn.misoenergy.org/Schedule%2026A%20Indicative%20Annual%20Charges106365.xlsx>.

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] The PJM ancillary service markets are regulation, synchronized reserve, primary reserve, and thirty minute reserve. 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.

The MMU analyzed measures of market structure, conduct and performance for the PJM Synchronized Reserve Market for the first three months of 2023.

Table 10-1 The synchronized reserve market results were competitive

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.

1 75 FERC ¶ 61,080 (1996).
2 Energy imbalance service refers to the real-time energy market.

The MMU analyzed measures of market structure, conduct and performance for the PJM Secondary Reserve Market for the first three months of 2023.

Table 10-2 The secondary reserve market results were competitive

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 included by 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 the first three months of 2023.

Table 10-3 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 93.2 percent of the hours in the first three months of 2023.
- Participant behavior in the PJM Regulation Market was evaluated as competitive in the first three months of 2023 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.

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 the first three months of 2023, the average primary reserve requirement was 2,541.1 MW in the RTO Zone and 2,521.6 in the MAD Subzone.
- **Market Concentration.** Both the Mid-Atlantic Dominion Subzone and the RTO Synchronized Reserve Zone Market were characterized by structural market power in the first three months of 2023. The average HHI for real-time synchronized reserve in the RTO Zone was 1362, which is classified as moderately concentrated. The average HHI for day-ahead synchronized reserve in the RTO Zone was 1321, which is classified as moderately concentrated. The average HHI for real-time synchronized reserve in the MAD Subzone was 4287, which is classified as highly concentrated. The average HHI for day-ahead synchronized reserve in the MAD Subzone was 2934, which is classified as highly concentrated.

Synchronized Reserve Market

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.

Market Structure

- **Supply.** In the first three months of 2023, the average supply of available synchronized reserve was 4,895.5 MW in the RTO Zone of which 2,172.4 MW was located in the MAD Subzone.
- **Demand.** The average hourly synchronized reserve requirement in the first three months of 2023 was 1,670.7 MW in the RTO Reserve Zone and 1,668.9 in the Mid-Atlantic Dominion Reserve Subzone.
- **Market Concentration.** The Mid-Atlantic Dominion Reserve Subzone Market was characterized by structural market power in the first three

months of 2023. The average HHI for real-time synchronized reserve in the RTO Zone was 861, which is classified as unconcentrated. The average HHI for day-ahead synchronized reserve in the RTO Zone was 881, which is classified as unconcentrated. The average HHI for real-time synchronized reserve in the MAD Subzone was 3060, which is classified as highly concentrated. The average HHI for day-ahead synchronized reserve in the MAD Subzone was 2454, which is classified as highly 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 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. 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 real-time price for synchronized reserve for all cleared market intervals in the MAD Subzone was $1.26 per MWh in the first three months of 2023. The weighted average real-time price for synchronized reserve for all cleared intervals in the RTO Synchronized Reserve Zone was $0.55 per MWh in the first three months of 2023.

Nonsynchronized Reserve

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.

Market Structure

- **Supply.** In the first three months of 2023, the average supply of eligible and available nonsynchronized reserve was 940.1 MW in the RTO Zone, of which 594.3 MW was available in the MAD Subzone.
- **Demand.** Demand for nonsynchronized reserve is the primary reserve requirement, which is satisfied jointly by synchronized and nonsynchronized reserves.[3]

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 to be available for nonsynchronized reserves. For non-hydroelectric units, PJM calculates the MW available from a unit based on the unit's energy offer. Hydroelectric units set their offered reserve amount. For all units, the offer price of nonsynchronized reserve is $0 per MWh.[4]

Market Performance

- **Price.** The nonsynchronized reserve price is determined by the marginal primary reserve resource. In the first three months of 2023, the nonsynchronized reserve weighted average real-time price for all intervals in the RTO Reserve Zone was $0.18 per MWh and the weighted average day-ahead price was $0.93 per MWh. In the first three months of 2023, the nonsynchronized reserve weighted average real-time price for all intervals in the MAD Reserve Subzone was $0.52 per MWh and the weighted average day-ahead price was $2.65 per MWh.

3 See PJM. "PJM Manual 11: Energy & Ancillary Services Market Operations," § 4.1 Overview of the PJM Reserve Markets, Rev. 122 (Oct. 1, 2022).
4 See PJM. "PJM Manual 11: Energy & Ancillary Services Market Operations," § 4.2.3 Reserve Market Resource Offer Structure, Rev. 122 (Oct. 1, 2022).

30-Minute Reserve Market

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. Secondary reserves can only be used to satisfy the 30-minute reserve requirement.

Market Structure

Supply. In the first three months of 2023, the average cleared 30-minute reserves was 16,489.8 MW in the day-ahead market and 4,443.3 MW in the real-time 30-minute market. Unlike the day-ahead market, the real-time market did not clear all available 30-minute reserves. In the first three months of 2023, an average of 14,528.5 MW of secondary reserves was scheduled in the day-ahead market and 2,170.3 MW of secondary reserves was scheduled in the real-time market.

Demand. The 30-minute reserve requirement is the maximum of: 150 percent of the synchronized reserve requirement; the largest active gas contingency; or 3,000 MW. In the first three months of 2023, the average 30-minute requirement was 3,206.3 MW.

Market Concentration. The 30-minute reserve market was unconcentrated in the first three months of 2023. The HHI for real-time 30-minute reserves was 881. The HHI for day-ahead 30-minute reserves was 439.

Market Behavior

In both the day-ahead and real-time 30-minute reserves markets, PJM uses 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. The amount of secondary reserve available from conventional resources are calculated based on the resources' energy offers. Hydroelectric resources, energy storage resources, and load response resources must specify their offered MW separately.

Market Performance

The average day-ahead price for secondary reserves in the first three months of 2023 was $0.00 per MWh. The average real-time price for secondary reserves in the first three months of 2023 was $0.00 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 the first three months of 2023, the average hourly offered supply of regulation for nonramp hours was 687.2 performance adjusted MW (709.1 effective MW). This was a decrease of 93.5 performance adjusted MW (a decrease of 70.9 effective MW) from the first three months of 2022. In the first three months of 2023, the average hourly offered supply of regulation for ramp hours was 1,043.4 performance adjusted MW (1,059.1 effective MW). This was a decrease of 103.8 performance adjusted MW (a decrease of 82.4 effective MW) from the first three months of 2022, when the average hourly offered supply of regulation was 1,147.2 performance adjusted MW (1,141.6 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 474.7 hourly average performance adjusted actual MW in the first three months of 2023. This is a decrease of 9.8 performance adjusted actual MW from the first three months of 2022, when the average hourly total regulation cleared performance adjusted actual MW for nonramp hours were 465.0 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 710.5 hourly average performance adjusted actual MW in the first three months of 2023. This is a decrease of 4.5 performance adjusted actual MW from the first three months of 2022, where the average hourly regulation cleared MW for ramp hours were 715.0 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 1.45 in the first three months of 2023 (1.67 in the first three months of 2022). The ratio of the average hourly offered supply of regulation to average hourly regulation demand (performance adjusted cleared MW) for ramp hours was 1.47 in the first three months of 2023 (1.58 in the first three months of 2022).
- **Market Concentration.** In the first three months of 2023, the three pivotal supplier test was failed in 93.2 percent of hours. In the first three months of 2023, the effective MW weighted average HHI of RegA resources was 2257 which is highly concentrated and the effective MW weighted average HHI of RegD resources was 1907 which is highly concentrated. The effective MW weighted average HHI of all resources was 1317, 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.[5] In the first three months of 2023, there were 150 resources following the RegA signal and 44 resources following the RegD signal.

Market Performance

- **Price and Cost.** The weighted average clearing price for regulation was $17.83 per MW of regulation in the first three months of 2023, a decrease of $27.40 per MW, or 60.6 percent, from the weighted average clearing price of $45.24 per MW in the first three months of 2022. The weighted average cost of regulation in the first three months of 2023 was $24.20 per MW of regulation, a decrease of 55.8 percent, from the weighted average cost of $54.76 per MW in the first three months of 2022.
- **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).[6]

5 See the *2021 State of the Market Report for PJM*, Vol. II, Appendix F "Ancillary Services Markets."
6 OATT Schedule 1 § 1.3BB. There are no ALR units currently providing black start service.

In the first three months of 2023, total black start charges were $16.6 million, including $16.5 million in revenue requirement charges and $0.1 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 the first three months of 2023 ranged from $0 in the OVEC and REC Zones to $4.8 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.[7] RTOs and their customers are not required to compensate generation resources for such reactive capability.[8] In the first three months of 2023, customers in PJM, nevertheless, paid $96.3 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.[9] 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 increased 0.5 percent from $95.8 million in the first three months of 2022 to $96.3 million in the first three months of 2023. Reactive capability charges increased 0.8 percent from $95.5 million in the first three months of 2022 to $96.3 million in the first three months of 2023. Total zonal reactive service charges ranged from $0 in the REC and OVEC Zones, to $13.4 million in the AEP Zone in the first three months of 2023.

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.[10] 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.[11] 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

7 OATT Attachment O.

8 *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).

9 OATT Schedule 2.

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

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

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.[12] 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 10-4 shows PJM ancillary services costs for the first three months of 1999 through 2023, 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.[13] 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 10-4 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.

Table 10-4 History of ancillary services costs per MWh of load: January through March, 1999 through 2023[14 15]

Year (Jan-Mar)	Regulation	Scheduling, Dispatch and System Control	Reactive	Synchronized Reserve	Total
1999	$0.04	$0.23	$0.25	$0.00	$0.52
2000	$0.21	$0.38	$0.37	$0.00	$0.96
2001	$0.49	$0.64	$0.22	$0.00	$1.35
2002	$0.24	$0.67	$0.16	$0.00	$1.07
2003	$0.65	$1.01	$0.22	$0.11	$1.99
2004	$0.54	$1.06	$0.26	$0.17	$2.03
2005	$0.47	$0.80	$0.25	$0.07	$1.59
2006	$0.48	$0.70	$0.28	$0.09	$1.55
2007	$0.58	$0.72	$0.25	$0.11	$1.66
2008	$0.59	$0.73	$0.30	$0.07	$1.69
2009	$0.38	$0.35	$0.34	$0.03	$1.10
2010	$0.34	$0.36	$0.35	$0.05	$1.10
2011	$0.27	$0.32	$0.38	$0.12	$1.09
2012	$0.18	$0.43	$0.48	$0.03	$1.12
2013	$0.28	$0.43	$0.63	$0.04	$1.38
2014	$0.63	$0.40	$0.37	$0.29	$1.68
2015	$0.32	$0.42	$0.36	$0.18	$1.28
2016	$0.11	$0.43	$0.37	$0.04	$0.95
2017	$0.11	$0.47	$0.42	$0.06	$1.06
2018	$0.28	$0.47	$0.41	$0.07	$1.23
2019	$0.10	$0.46	$0.41	$0.04	$1.01
2020	$0.08	$0.45	$0.46	$0.01	$1.00
2021	$0.12	$0.53	$0.46	$0.04	$1.15
2022	$0.31	$0.39	$0.48	$0.07	$1.25
2023	$0.15	$0.51	$0.51	$0.02	$1.19

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

12 *Id.*; see also "PJM Manual 12: Balancing Operations, Rev. 47 (Oct. 1, 2022). § 3.6 (Primary Frequency Response).
13 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.
14 Note: The totals in Table 10-4 account for after the fact billing adjustments made by PJM and may not match totals presented in past reports.
15 Reactive totals include FERC approved rates for reactive capability.

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 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.[16])
- The MMU recommends that the two signal regulation market design be replaced with a one signal regulation market design. (Priority: Medium. New recommendation. Status: Not adopted.)
- 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.[17] FERC rejected.[18])
- The MMU recommends that the lost opportunity cost calculation used in the regulation market be based on the resource's dispatched energy

16 162 FERC ¶ 61,295 (2018), *reh'g denied*, 170 FERC ¶ 61,259 (2020).
17 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.
18 162 FERC ¶ 61,295 (2018), *reh'g denied*, 170 FERC ¶ 61,259 (2020).

offer schedule, not the lower of its price or cost offer schedule. (Priority: Medium. First reported 2010. Status: Not adopted. FERC rejected.[19])

- 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.[20])
- The MMU recommends enhanced documentation of the implementation of the regulation market design. (Priority: Medium. First reported 2010. Status: Not adopted. FERC rejected.[21])
- 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.)
- 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.)

19 *Id.*
20 *Id.*
21 *Id.*

- 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 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 black start planning and coordination be on a regional basis and not on a zonal basis and that the costs of black start service be shared equally across the region. (Priority: medium. New recommendation. 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.[22] 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 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.[23] (Priority: Medium. First reported 2020. Status: Not adopted.)

22 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.

23 *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>.

Conclusion

The design of the PJM Regulation Market is significantly flawed.[24] 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.[25] The PJM/MMU joint proposal addressed 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.[26] The MMU and PJM separately filed requests for rehearing, which were denied by order issued March 26, 2020.[27]

The October 1, 2022, changes included 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 has occurred since October 2022, except during Winter Storm Elliott. 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.

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.

24 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).
25 18 CFR § 385.211.
26 162 FERC ¶ 61,295 (2018).
27 170 FERC ¶ 61,259 (2020).

PJM Reserve Markets

Reserves resources are scheduled and paid for the availability to respond to a loss of supply on the system by quickly increasing their energy output.

PJM schedules reserves to satisfy defined reserve service requirements. There are three reserve services: the synchronized reserve service, provided by resources that are online and able to respond within 10 minutes; the primary reserve service, provided by resources, online or offline, that are able to respond within 10 minutes; and the 30-minute reserve service, provided by resources, online or offline, able to respond within 30 minutes. Each reserve service requires a specified number of MW, known as that service's reserve requirement, that should be available at all times in order to cover a potential loss of supply event. As a result of transmission limits, there are also locational requirements for each reserve service, except for the 30-minute reserve service.[28] PJM currently allows for one active reserve subzone when satisfying reserve requirements, and the satisfaction of reserve requirements in the subzone counts towards the satisfaction of requirements for the entire RTO Reserve Zone.[29]

The size of a service's requirement depends on the contingencies that service is designed to address.[30] For synchronized reserve, this is the loss, in a single event, of the largest generator or group of generators, called the "most severe single contingency", or MSSC. For primary reserve, this is 150 percent of the MSSC plus 190 MW. For 30-minute reserve, this is the greater of the largest gas contingency, the primary reserve requirement, and 3,000 MW. PJM can temporarily increase reserve requirements due to emergencies and weather alerts, and when risks during maintenance work change the largest contingency. Table 10-5 shows the instances identified by the MMU when PJM increased the reserve requirements during the first three months of 2023. The services are nested, such that satisfaction of the synchronized reserve requirement counts towards the satisfaction of the primary reserve requirement, which counts towards the satisfaction of the 30-minute reserve requirement.

Table 10-5 Temporary adjustments to 30-minute, primary, and synchronized reserve requirements: January through March, 2023[31]

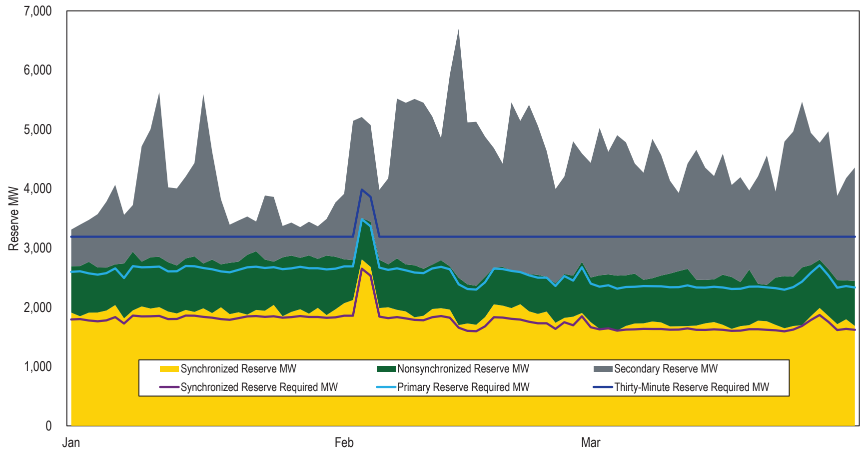
From	To	Number of Hours	Amount of Adjustment
7-Nov-22	2-Feb-23	2,091	30-Minute Reserve (0 MW), Primary Reserve (45 MW), Synchronized Reserve (30 MW)
3-Feb-23	4-Feb-23	28	30-Minute Reserve (895 MW), Primary Reserve (894 MW), Synchronized Reserve (894 MW)

PJM must also comply with reserve requirements imposed by NERC. NERC Performance Standard BAL-002-3, Disturbance Control Standard defines a requirement for synchronized reserve and for primary reserve, but not for 30-minute reserve.

There are three reserve products that can be purchased from resources for satisfying PJM's reserve requirements: synchronized reserves, which are online resources that can respond within 10 minutes; non-synchronized reserves, which are offline generators that can respond within 10 minutes; and secondary reserves, which are resources, online or offline, that can respond in 10 to 30 minutes. A product can only be used to satisfy a reserve service's scheduling requirement if it also meets that service's response time requirement. Figure 10-1 shows how reserve products were scheduled in real time to meet the reserve service requirements in the first three months of 2023. On February 3 and February 4, PJM had increased reserve requirements during conservative operations due to cold weather.

28 See PJM. "PJM Manual 11: Energy & Ancillary Services Market Operations," § 4.3.1 Locational Aspect of Reserves, Rev. 122 (October 1, 2022).
29 See PJM. "PJM Manual 11: Energy & Ancillary Services Market Operations," § 4.4.1 Product and Locational Substitution, Rev. 122 (October 1, 2022).
30 See PJM. "PJM Manual 11: Energy & Ancillary Services Market Operations," § 4.3 Reserve Requirement Determination, Rev. 122 (October 1, 2022).
31 The MW values for the first listed adjustment during the first three months of 2023 were previously estimated incorrectly.

Figure 10-1 Daily average reserve products and daily average reserve requirements: January through March, 2023



PJM uses market mechanisms to schedule resources. In general, products that meet stricter response-time requirements, which can be used to satisfy multiple reserve requirements, are priced higher. Synchronized reserve, regarded as the highest quality product, is usually the most expensive. However, PJM seeks to reduce overall cost when purchasing reserves, which are co-optimized with energy. For example, if it is somehow more economic to satisfy the primary reserve requirement using only synchronized reserves, PJM will do so.

Implementation of PJM Reserve Markets

While the primary reserve requirement and 30-minute reserve requirement can be satisfied using multiple products, the products are purchased separately. There are separate markets for synchronized reserves, non-synchronized reserves, and secondary reserves.[32] Each product's reserve market has a day-ahead component and a real-time component. The obligations of a reserve resource depend on its real-time assignment, which in turn depends on how the resource clears the day-ahead and real-time markets. A resource that cleared one market is not guaranteed to have cleared the other market, and a resource that cleared both markets need not clear the same amount in real time as it did day ahead.

In general, the amount of reserve MW available from a resource is calculated by PJM based on the parameters in the resource's energy offer and reserve parameters. Some resources types, such as hydroelectric resources, energy storage resources, and load response resources, can specify offer amounts.[33] In general, resources that choose to participate in the energy market are required to also participate in the reserve market. 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.[34] [35] 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.[36]

In general, the amount of reserve MW a resource can provide is based on the resource parameters in that resource's energy offer. However, a generation resource can request a maximum MW value for its reserve offer (synchronized, secondary, or both individually) 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.[37] 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.

The scheduling of resources to meet PJM's operational requirements includes multiple steps to commit resources, dispatch resources, and calculate clearing prices.[38] Each program in the commitment and dispatching process estimates

32 See PJM. "PJM Manual 11: Energy & Ancillary Services Market Operations," § 4.4.1 Product and Locational Substitution, Rev. 122 (October 1, 2022).

33 See PJM. "PJM Manual 11: Energy & Ancillary Services Market Operations," § 4.2.3 Reserve Market Resource Offer Structure, Rev. 122 (October 1, 2022).
34 See PJM. "PJM Manual 11: Energy & Ancillary Services Market Operations," § 4.2.1 Reserve Market Eligibility, Rev. 122 (October 1, 2022).
35 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).
36 See *id.*
37 See PJM. "PJM Manual 11: Energy & Ancillary Services Market Operations", § 4.2.2.1 Communication for Reserve Capability Limitation, Rev. 122 (October 1, 2022).
38 For more on the market solution software, see the *2022 Annual State of the Market Report for PJM*, Appendix E - Ancillary Service Markets.

future needs, resulting in scheduling reserves on a five-minute basis. The day-ahead market solution software schedules resources by hour, looking ahead to the operating day.[39] The real-time 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).[40]

Due to the time taken for their start-up and notification procedures, some resources can only be scheduled in the early steps of PJM's commitment and dispatching process. Depending on their physical run-time requirements, resources are described as either flexible or inflexible. Inflexible resources, such as some demand response resources and condensers, are those that must run for at least one hour and are only committed in real-time by the ASO or manually by a PJM operator. Flexible resources can be committed by RT SCED later in the process.

In general, resources do not have to clear the same amounts in the real-time and day-ahead markets, and a resource that cleared one of the markets is not guaranteed to have cleared the other. However, if an inflexible condenser or an inflexible economic load response resource has a day-ahead assignment, that assignment is also applied to the operating day.[41]

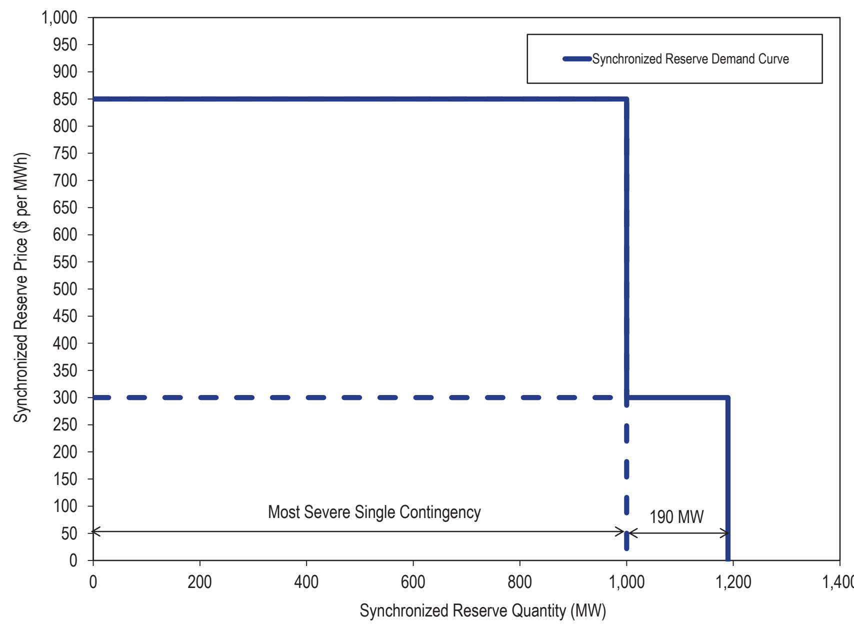
There is no explicit demand for non-synchronized reserves nor for secondary reserves. There is a defined demand for synchronized reserves, primary reserves, and 30-minute reserves. PJM's administratively defined demand curve for reserves is called the Operating Reserve Demand Curve. The first step of the demand curves for primary, synchronized reserves, and 30-minute reserves are set at the minimum reserve requirement for each product, known as the services' reliability requirements. Since the primary and synchronized minimum reserve requirements are based on the actual output of the most severe single contingency, 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 extended primary, extended synchronized, and extended 30-minute reserve demand curves extends the reserve requirements, known as the services' extended reserve requirements. The extended requirements are defined as the 30-minute, primary, and synchronized reserve requirements, plus 190 MW, plus any additional requirement due conservative operations, weather alerts, or other system conditions. 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.

39 See PJM. "PJM Manual 11: Energy & Ancillary Services Market Operations", § 4.4.2 Day-ahead Reserve Market Clearing, Rev. 122 (October 1, 2022).

40 See PJM. "PJM Manual 11: Energy & Ancillary Services Market Operations", § 4.4.3 Real-time Reserve Market Clearing, Rev. 122 (October 1, 2022).

41 See *id.*

Figure 10-2 An example of a real-time operating reserve demand curve, including the permanent second step



During periods of shortage pricing, the reserve market clearing prices can be higher than the limit shown in Figure 10-2.

Credits and charges for reserves have 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 reserve markets.

The real-time component is added to 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 any shortfall charge for failing to provide the service. 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. For some services, the amount of MW for which a resource is credited is capped at a value less than the scheduled amount. This capping accounts for things like a resource's real-time energy output, and prevents crediting a resource for a reserve amount that it did not actually provide.

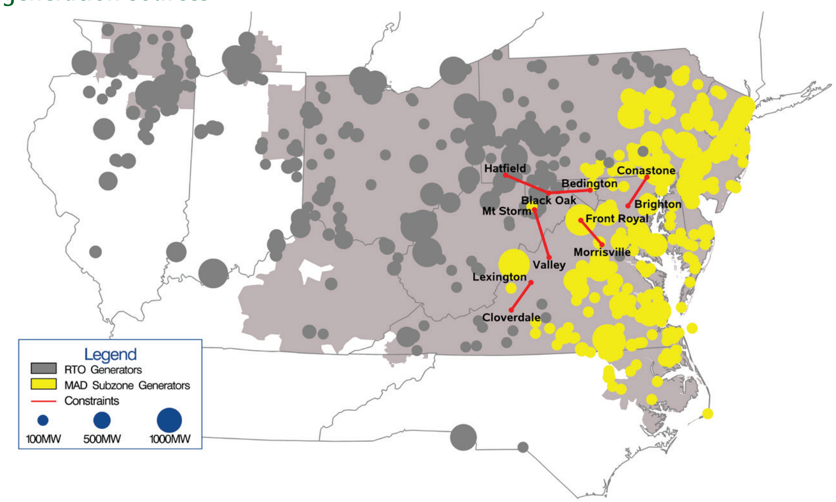
Reserve Subzones

Reserve subzones address transmission limits that may prevent the lowest cost reserves from being available throughout the RTO. A reserve subzone has its own reserve requirement. The RTO Reserve Zone has only one active subzone at any time. In practice, PJM has maintained only one subzone, the Mid-Atlantic Dominion Reserve Subzone (MAD), and in every market solution the most limiting constraining path sets the transfer limit between the RTO and MAD Subzone. The price in MAD may exceed the price in the rest of RTO when the constraints are binding.

The choice of MAD was a result of historical congestion patterns. Transmission limits at times required maintaining out of merit reserves in the MAD area. On most days, the MAD Subzone is no longer binding. 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 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, and new subzones can be defined as needed.[42] In the first three months of 2023, PJM did not change the subzone.

Figure 10-3 is a map of constraints and major generation sources, showing how the constraints separating the RTO Zone and MAD Subzone are defined by underlying grid topology. 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 frequently binding constraints in the first three months of 2023 were Bedington-Black Oak, Brighton-Conastone, and Hunterstown-Conastone.

Figure 10-3 PJM RTO Zone and MAD Subzone map of constraints and generation sources



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

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.[43] The NERC requirement is 100 percent compliance and status must be reported quarterly. PJM implements this contingency reserve requirement using primary reserves.[44] 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.

Market Structure

Demand

The NERC standard requires a control area to carry primary reserve MW equal to or greater than the largest single contingency (MSSC).[45] The largest single contingency is usually the output of the largest generating unit to which PJM adds 190 MW, defined as the extended synchronized reserve requirement. 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.[46] PJM requires primary reserves equal to 150 percent of the largest single contingency for each market solution (ASO, IT SCED, and RT SCED).[47] 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. PJM can also increase the primary and synchronized reserve requirement in cases of hot weather or cold weather alerts or escalating emergency procedures.[48]

In the first three months of 2023, the average primary reserve requirement for the RTO Zone was 2,541.1 MW. The average primary reserve requirement in the MAD Subzone was 2,521.6 MW. The average synchronized reserve requirement in the RTO Zone was 1,762.8 MW. The average synchronized reserve requirement in the MAD Subzone was 1,749.8 MW.

Supply

In the first three months of 2023, the demand for primary reserve was satisfied by synchronized reserves and nonsynchronized reserves. After the synchronized reserve requirement is satisfied, the remainder of the primary reserve requirement is met from the least expensive combination of synchronized and nonsynchronized reserves.

In the first three months of 2023, in the MAD Subzone, there was an average of 594.3 MW of eligible nonsynchronized reserve supply available to meet the demand for primary reserve (Table 10-6). In the RTO Zone, an average of 940.1 MW of nonsynchronized reserve supply was available to meet the average demand of 2,541.1 MW (Table 10-7).

In Table 10-6 and Table 10-7, the average synchronized reserve in the first nine months of 2022 is the sum of tier 1 synchronized reserve, which was estimated, and tier 2 synchronized reserve, which was scheduled.

43 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.
44 See PJM. "PJM Manual 10: Pre-Scheduling Operations," § 3.1 Reserve Definitions, Rev. 42 (Oct. 1, 2021).
45 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>.
46 See PJM. "PJM Manual 11: Energy & Ancillary Services Market Operations" § 4.3 Reserve Requirement Determination, Rev. 122 (Oct. 1, 2022).
47 See PJM. "PJM Manual 13: Emergency Operations," § 2.2 Reserve Requirements, Rev. 85 (Oct. 1, 2022).
48 See *id.*

Table 10-6 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 the first three months of 2023.

Table 10-6 Average monthly reserves used to satisfy the primary reserve requirement, MAD Subzone: January 2022 through March 2023

Year	Month	Synchronized Reserve MW	Nonsynchronized Reserve MW	Total Primary Reserve MW
2022	Jan	1,667.1	1,344.3	3,011.4
2022	Feb	1,708.6	1,277.3	2,985.8
2022	Mar	1,690.8	1,097.0	2,787.9
2022	Apr	1,576.9	1,190.0	2,766.9
2022	May	1,719.0	1,109.9	2,828.9
2022	Jun	1,785.2	1,288.6	3,073.8
2022	Jul	1,723.0	1,150.0	2,873.0
2022	Aug	1,742.0	1,236.6	2,978.5
2022	Sep	1,618.5	967.2	2,585.8
2022	Average (Jan-Sep)	1,692.3	1,184.5	2,876.9
2022	Oct	1,830.7	810.2	2,640.9
2022	Nov	1,819.6	857.4	2,677.0
2022	Dec	1,896.2	822.8	2,719.1
2022	Average (Oct-Dec)	1,848.8	830.1	2,679.0
2023	Jan	1,932.9	791.9	2,724.8
2023	Feb	1,955.1	672.8	2,627.9
2023	Mar	1,695.5	678.2	2,373.7
2023	Average	1,861.2	715.7	2,573.8

Table 10-7 shows the average dispatch solution reserves, by type of reserve, used by the RT SCED market solution to satisfy the primary reserve requirement in the RTO Zone from October 2022 through March 2023.

Table 10-7 Average monthly reserves used to satisfy the primary reserve requirement, RTO Zone: October 2022 through March 2023

Year	Month	Synchronized Reserve MW	Nonsynchronized Reserve MW	Total Primary Reserve MW
2022	Jan	2,070.1	1,900.9	3,970.9
2022	Feb	2,205.8	1,863.6	4,069.4
2022	Mar	1,961.7	1,996.8	3,958.5
2022	Apr	1,748.5	1,694.9	3,443.4
2022	May	2,077.5	1,822.0	3,899.5
2022	Jun	2,187.0	2,099.3	4,286.3
2022	Jul	2,057.3	1,988.3	4,045.6
2022	Aug	2,086.5	2,083.9	4,170.4
2022	Sep	2,040.4	1,850.7	3,891.1
2022	Average (Jan-Sep)	2,048.3	1,922.3	3,970.6
2022	Oct	1,831.7	955.1	2,786.8
2022	Nov	1,822.1	1,011.4	2,833.5
2022	Dec	1,899.9	964.8	2,864.8
2022	Average (Oct-Dec)	1,851.2	977.1	2,828.4
2023	Jan	1,934.6	861.0	2,795.6
2023	Feb	1,974.8	718.4	2,693.2
2023	Mar	1,722.1	812.4	2,534.5
2023	Average	1,877.2	799.9	2,673.9

Market Concentration

In the first three months of 2023, 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. Table 10-8 shows the average HHI for primary reserves in the first three months of 2023.

Table 10-8 Average primary reserve HHI: January through March, 2023

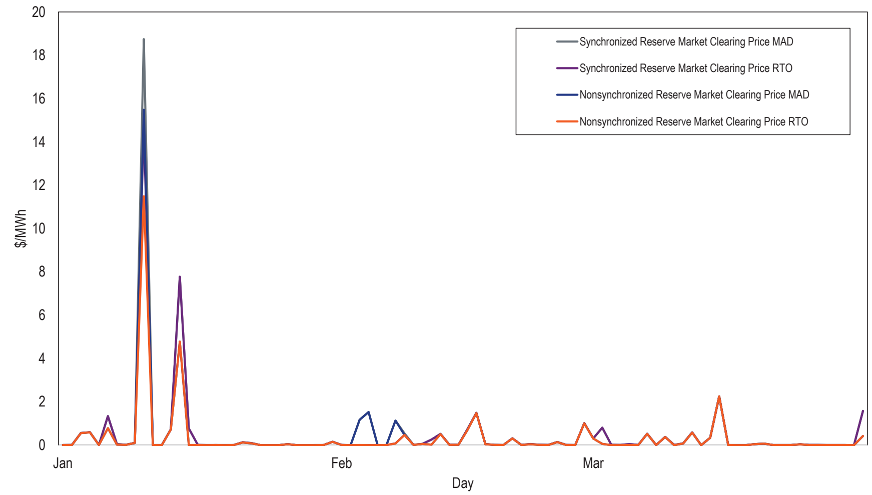
Location	Market	Average HHI	Percent of Intervals Max Market Share Above 20%
RTO	RT	1362	91.0%
RTO	DA	1321	91.6%
MAD	RT	4287	99.8%
MAD	DA	2934	99.8%

Prices

Figure 10-4 shows daily weighted average synchronized and nonsynchronized market clearing prices in the first three months of 2023. The MAD SRMCP and RTO SRMCP prices diverged in 171 five-minute intervals, 0.7 percent of the total 25,908 intervals in the first three months of 2023.

The prices of synchronized reserve and nonsynchronized reserve spiked on January 10, 2023 in the RTO Reserve Zone and the MAD Reserve Subzone. During this time, shortage pricing was used for primary reserve for three intervals and for synchronized reserve for one interval.

Figure 10-4 Daily average market clearing prices ($/MWh) for synchronized reserve and nonsynchronized reserve: January through March, 2023



Synchronized Reserve

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.

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. 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 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).[49]

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.

Demand

Demand for synchronized reserve comes from the reserve requirement for the synchronized reserve service, based on the largest single contingency (also known as the most severe single contingency, or MSSC). The largest single contingency is usually the output of the largest generating unit to which PJM adds 190 MW, defined as the extended synchronized reserve requirement.

A plot of the daily average real-time requirement for synchronized reserve can be seen in Figure 10-1. In the first three months of 2023, the average real-time synchronized requirement in the RTO Reserve Zone was 1,762.8 MW and the average day-ahead requirement was 1,747.6 MW. In the MAD Reserve Subzone, the average real-time synchronized requirement was 1,749.8 MW and the average day-ahead requirement was 1,746.7 MW.

Supply

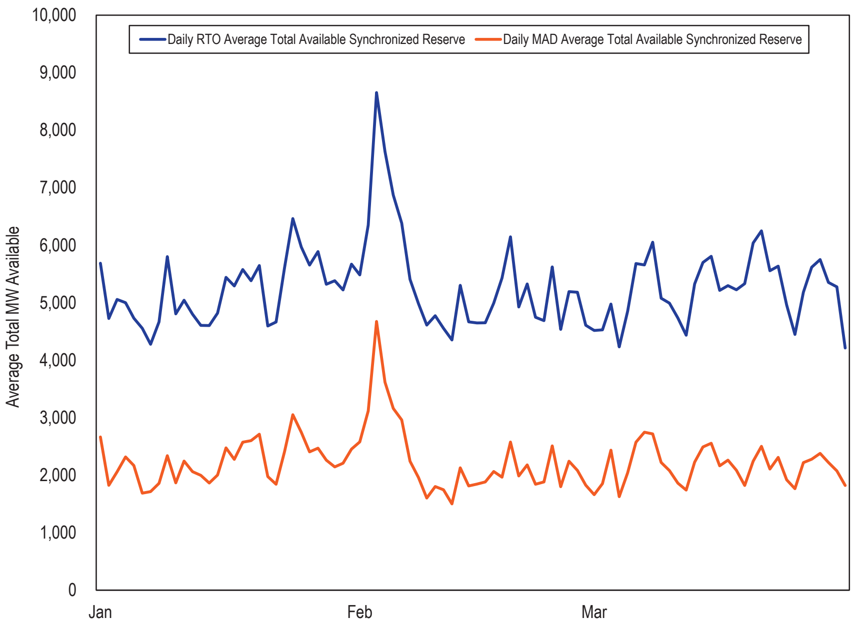
The supply of synchronized reserves consists of all unloaded capacity that can convert to energy in ten minutes from online resources and all synchronized load that can curtail in ten minutes. Any of this capacity that is not offered as dispatchable in the energy market does not have a lost opportunity 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 is the lesser of a resource's 10-minute ramp and the difference between its energy output and its economic maximum output.

In the first three months of 2023, the average supply of daily offered and eligible synchronized reserve was 5,261.5 MW in the RTO Zone, of which 2,220.3 MW was located in the MAD Subzone. Figure 10-5 shows the daily average available synchronized reserve MW.

49 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).

Figure 10-5 Daily Average Available Synchronized Reserve: January through March, 2023



Market Concentration

Table 10-9 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 first three months of 2023. In the first three months of 2022, the MAD real-time and day-ahead synchronized reserve markets were highly concentrated. In the first three months of 2023, the RTO real-time market synchronized reserve was unconcentrated and the RTO day-ahead market was moderately concentrated.

Table 10-9 Day-ahead and real-time synchronized reserve Average HHI, January through March, 2023[50]

Location	Market	Average HHI	Percent of Intervals Max Market Share Above 20%
RTO	RT	861	25.5%
RTO	DA	881	27.7%
MAD	RT	3060	99.4%
MAD	DA	2454	92.4%

Market Behavior

The synchronized reserve 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.[51] These values are listed in Table 10-10. For resources that do not set their offer price, the offer price is treated as $0 per MWh.

Table 10-10 Expected values of the synchronized reserve penalty

Year	Month	Value of Expected Penalty ($/MWh)
2022	Oct	$0.02
2022	Nov	$0.02
2022	Dec	$0.11
2023	Jan	$0.09
2023	Feb	$0.14
2023	Mar	$0.11

Market Performance

Figure 10-6 shows the daily unweighted average prices for synchronized reserve in the real-time and day-ahead markets. Higher prices on January 10 are due to the use of shortage pricing for one interval. Higher prices on February 3 and February 4 are due to an increased synchronized reserve requirement during conservative operations due to cold weather.

50 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.
51 See PJM. "PJM Manual 15: Cost Development Guidelines," § 4.7 Synchronized Reserve, Rev. 42 (October 28, 2022).

Figure 10-6 Day-ahead and real-time synchronized reserve market clearing prices: January through March, 2023

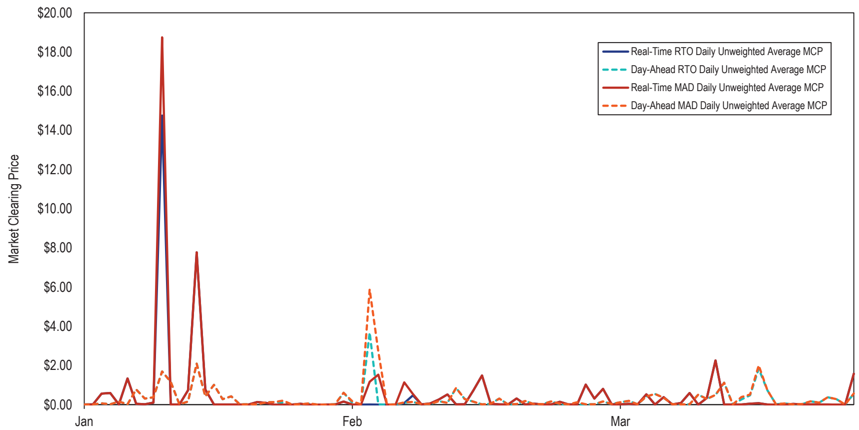


Table 10-11 compares the dispatch-run and pricing-run weighted average prices for the day-ahead and real-time markets. For the real-time values, these are the LPC prices weighted using the RT SCED MW. For the day-ahead values, these are the DA prices weighted using the DA dispatch MW. The prices being compared include the RTO Reserve Zone prices and the reserve subzone prices. PJM dispatchers can update assignments after RT SCED has run, so these weights differ from the weighted average value reported elsewhere in this section.[52]

Table 10-11 Day-ahead and real-time fast start pricing in the synchronized reserve market: October 2022 through March 2023[53]

		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	$0.41	$0.44	$0.03	6.7%	$0.45	$0.86	$0.41	89.5%
2022	Nov	$1.40	$1.48	$0.08	6.0%	$0.14	$0.34	$0.20	144.7%
2022	Dec	$3.14	$3.33	$0.19	6.2%	$35.71	$31.53	($4.18)	(11.7%)
2023	Jan	$0.34	$0.36	$0.01	3.8%	$0.93	$1.01	$0.09	9.2%
2023	Feb	$0.54	$0.59	$0.04	7.8%	$0.27	$0.38	$0.11	38.9%
2023	Mar	$0.34	$0.35	$0.01	4.3%	$0.15	$0.26	$0.11	68.9%

Table 10-12 shows total synchronized reserve payments by month for October 2022 through March 2023. Balancing credits for all but one month are negative, because, on average, resources buy back their day-ahead positions at higher real-time 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. There were no synchronized reserve events that lasted for 10 or more minutes in February 2023 and March 2023, so there are no shortfall charges for those months in Table 10-12.

Table 10-12 Total payments and charges by month: October 2022 through March 2023

Year	Month	Total Day-Ahead Credits	Total Balancing MCP Credits	Total LOC Credits	Total Shortfall Charges	Total Credits
2022	Oct	$676,211	($67,992)	$1,708,506	$19,273	$2,297,451
2022	Nov	$2,275,752	($121,388)	$1,593,328	$14,882	$3,732,809
2022	Dec	$4,874,437	($15,512,268)	$12,988,842	$11,195,016	($8,844,005)
2023	Jan	$505,419	($114,061)	$983,619	$335,995	$1,038,982
2023	Feb	$735,351	$99,577	$495,474	$0	$1,330,401
2023	Mar	$439,364	($5,106)	$744,883	$0	$1,179,141

Table 10-13 provides the day-ahead and real-time synchronized reserve by resource type and fuel type for the first three months of 2023. For synchronized reserve, 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 10-13 only shows the capped value, excluding the scheduled MW. During

52 See PJM. "PJM Manual 01: Control Center and Data Exchange Requirements," § 1.7 Dispatch Management Tool (DMT), Rev. 46 (July 27, 2022).
53 The weights used to calculate these weighted average prices are different from previous reports.

Winter Storm Elliott, many resources bought back day-ahead reserve positions at shortage prices, resulting in negative balancing credits and negative total credits for some resources.

Table 10-13 Day-ahead and Real-time Synchronized Reserve by Resource Type and Fuel Type: January through March, 2023

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	779,690	776,613	$365,519	$88,709	$1,482,628	$144,439	$1,792,417
Combined Cycle	1,207,330	1,250,187	$746,636	($211,524)	$358,863	$89,963	$804,012
Steam - Coal	1,245,211	1,230,603	$279,426	($22,515)	$186,730	$32,399	$411,243
DSR	48,479	310,973	$75,275	$248,856	$5,103	$54,538	$274,695
Hydro - Run of River	185,623	138,962	$54,101	($3,720)	$43,356	$155	$93,582
Hydro - Pumped Storage	272,585	142,776	$73,682	($75,005)	$51,819	$0	$50,496
CT - Oil	2,611	8,024	$13,838	$19,591	$16,270	$8,104	$41,595
Steam - Other	41,032	5,909	$9,940	($1,573)	$26,079	$1,530	$32,915
Steam - Natural Gas	61,937	47,831	$21,344	($11,155)	$25,808	$3,565	$32,431
RICE - Other	89,693	21,094	$37,294	($49,136)	$25,946	$1,303	$12,801
Steam - Oil	90	974	$1,943	$587	$0	$0	$2,530
CT - Other	0	0	$0	$0	$0	$0	$0
RICE - Natural Gas	790	2,168	$1,137	($2,706)	$1,375	$0	($193)
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
RICE - Oil	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

Before the October 1 changes, DSR was limited to 33 percent of the cleared synchronized reserves. This limitation was removed. In the first three months of 2023, DSR was more than 33 percent of the cleared synchronized reserves in 7 of 25,908 five-minute intervals. In all of the 7 intervals, DSR exceeded 33 percent of the RT MW, but not the DA MW. During these 7 intervals, on average, DSR made up 62.6 percent of the total synchronized reserve MW. Figure 10-7 and Figure 10-8 show the portion of synchronized reserve provided by DSR. As seen in the figures, the absolute amount of synchronized reserve provided by DSR has not significantly changed, nor has the amount relative to the total amount of synchronized reserve. In most of the six months since the October 1 changes, the daily average amount was lower that it had been.

Figure 10-7 Daily average synchronized reserve from DSR and non-DSR: January through March, 2023

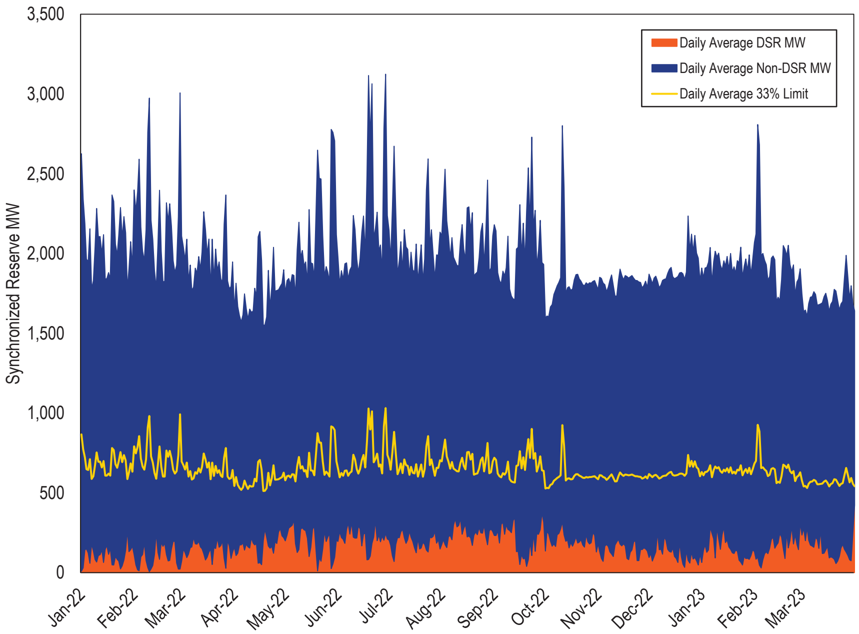
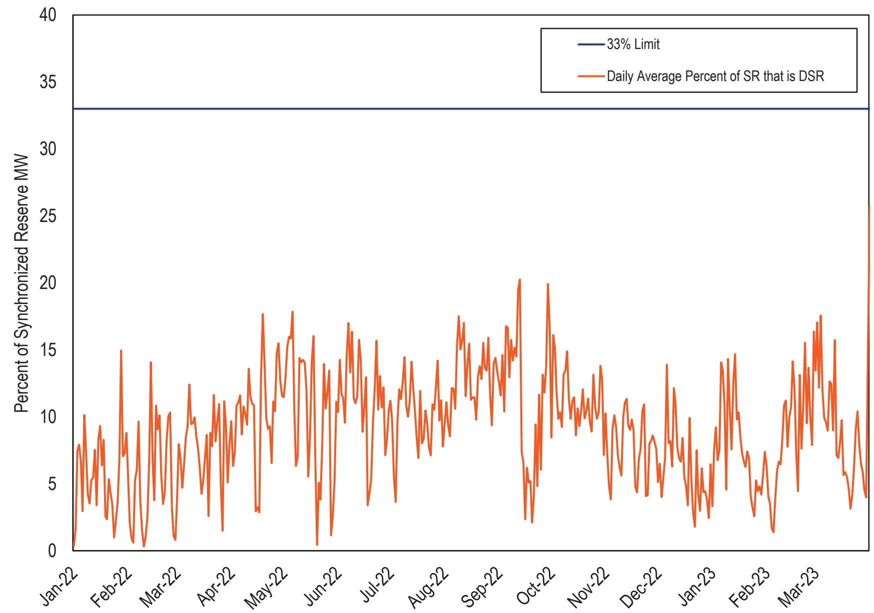


Figure 10-8 Daily average percent of synchronized reserve that is demand response: January through March, 2023



Synchronized Reserve Performance

Resources providing synchronized reserves are paid for being available to respond to a synchronized reserve event. Resources are not directly paid for their response to an event, though they are obligated to provide their full scheduled MW during an event and are charged when failing to do so. If no event occurs, resources are still paid.

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 output between one minute before the event and one minute after the event.[54] 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

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

failure of a scheduled resource to perform during any synchronized reserve event lasting 10 minutes or longer.

In the first three months of 2023, compliance with calls to respond to actual synchronized reserve events was significantly less than 100 percent. Table 10-14 shows the average amount of scheduled synchronized reserve MW that responded to events 10 minutes or longer from January 2016 through March 2023. PJM experienced five synchronized reserve events during Elliott (December 23 and 24). 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 below average for other events and reduced the average for the last three months of 2022 (Table 10-14).

Table 10-14 Average synchronized reserve response for events longer than 10 minutes, January 2016 through March 2023

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%
2023 (Jan - Mar)	2	56.9%

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 time, in number of days, since the start of the previous event over the previous two years or, if less, the number of days since the resource last failed to fully respond. For example, the maximum IPI effective January 1, 2023, is 21 days and was calculated using the events from November 1, 2020 through October 31, 2022.[55]

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.[56] 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 82 days from its current level of 21 days. 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.

55 See "2022 Third Quarter Synchronized Reserve Performance," PJM presentation to the Operations Committee. (December 8, 2022) <https://www.pjm.com/-/media/committees-groups/committees/oc/2022/20221208/item-12---synchronous-reserve-update.ashx>.

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

Table 10-15 compares the outcomes of the PJM penalty structure for the first three months of 2023 with the outcomes of the proposed MMU penalty structure following its recommendations. In the first three months of 2023, there were two spinning events that lasted 10 minutes or longer: one on January 5 and one on January 10 (Table 10-16).

Table 10-15 Comparison of synchronized reserve shortfall penalties current IPI vs. MMU recommended: January through March, 2023

Penalty Type	Current PJM Penalty	MMU Recommended Penalty
Day Of Event	$335,995	$372,872
Retroactive Charges	$2,066,056	$3,418,370
Total Penalties	$2,402,052	$3,791,242

Table 10-16 shows synchronized reserve event response compliance for events that lasted 10 minutes or longer as reported by PJM at Operating Committee meetings, using only response from estimated and cleared synchronized reserves. In the first three months of 2023, there were two events that were 10 minutes or longer. 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. 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.[57] PJM, in practice, not only corrects the ACE disturbance that led to the event but over corrects. In both of the spinning events in the first three months of 2023, the ACE recovered not just to the NERC required level of zero but overshot by over 1,000 MW in both cases.

Table 10-16 Synchronized reserve events 10 minutes or longer, response compliance as reported by PJM[58], RTO Reserve Zone: October 2022 through March 2023

Spin Event	Duration (Minutes)	Synchronized Reserve Scheduled (MW)	Synchronized Reseve Response (MW)	Synchronized Reserve Penalty (MW)	Synchronized Reserve Response Percent
29-Oct-2022 1412 (EPT)	11.9	1,857.9	567.1	1,290.8	30.5%
29-Nov-2022 1630 (EPT)	16.8	1,785.3	949.0	836.3	53.2%
23-Dec-2022 1014 (EPT)	11.1	1,791.4	948.9	842.5	53.0%
23-Dec-2022 1617 (EPT)	111.5	1,845.6	812.3	1,033.3	44.0%
24-Dec-2022 0501 (EPT)	25.7	1,766.5	329.9	1,436.6	18.7%
24-Dec-2022 0223 (EPT)	30.6	1,664.8	534.7	1,130.1	32.1%
24-Dec-2022 0423 (EPT)	87.5	1,097.0	258.6	838.4	23.6%
2022 Average	42.2	1,686.9	628.6	1,058.3	36.4%
05-Jan-2023 1243 (EPT)	11.6	1,713.6	1,010.7	702.9	59.0%
10-Jan-2023 0726 (EPT)	17.5	2,368.1	1,289.7	1,078.4	54.5%
2023 Average	14.5	2,040.9	1,150.2	890.7	56.7%

History of Synchronized Reserve Events

Synchronized reserve is designed to provide relief for disturbances.[59] [60] A disturbance is defined as loss of the lesser of 900 MW and 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.

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

58 *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.

59 *2012 State of the Market Report for PJM*, Appendix E – PJM's DCS Performance.

60 See PJM. "PJM Manual 12: Balancing Operations," § 4.1.2 Loading Reserves, Rev. 47 (Oct. 1, 2022).

From January 2018 through March 2023, PJM experienced 93 synchronized reserve events, approximately 1.5 events per month, with an average duration of 11.5 minutes. Table 10-17 shows these events with their region and their duration rounded to the nearest minute.

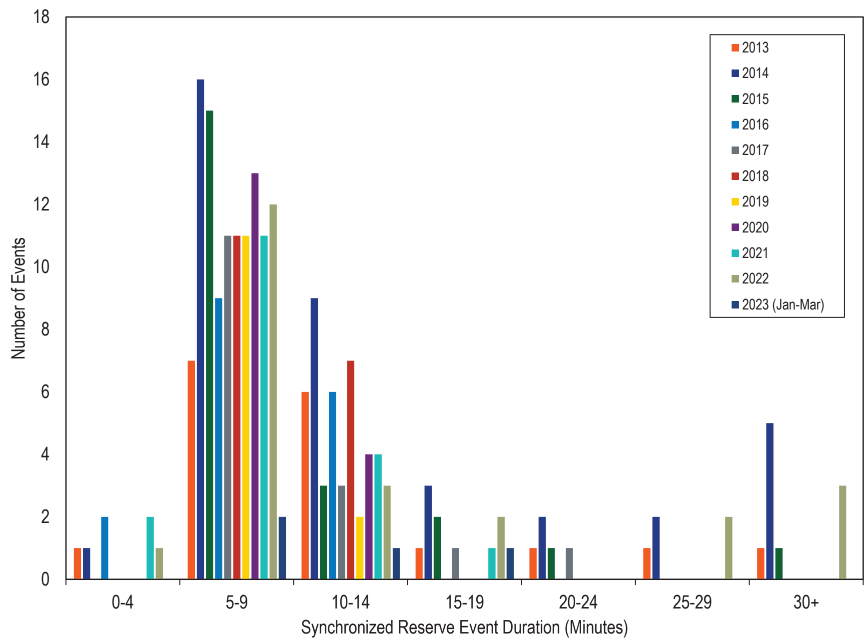
Table 10-17 Synchronized reserve events: January 2018 through March 2023[61]

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	05-Jan-2023 1243 (EPT)	RTO	12
27-Jul-2019 2331 (EPT)	RTO	7	21-Jul-2021 1828 (EPT)	RTO	5	10-Jan-2023 0726 (EPT)	RTO	18
11-Aug-2019 1214 (EPT)	RTO	8	25-Jul-2021 1617 (EPT)	RTO	6	26-Jan-2023 1443 (EPT)	MAD	7
03-Sep-2019 1339 (EPT)	MAD	9	23-Aug-2021 1644 (EPT)	RTO	18	02-Feb-2023 0606 (EPT)	RTO	8
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			

61 For full history of spinning events, see the *2022 State of the Market Report for PJM*, Appendix E - Ancillary Service Markets.

Figure 10-9 shows spin event durations over the past 11 years.[62] 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 10-9 Synchronized reserve events duration distribution curve: January 2013 through March 2023



62 These durations were rounded to the nearest minute in previous reports. They are no longer rounded.

Nonsynchronized Reserve

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 nonsynchronized reserve market has a day-ahead and a real-time component. There are no lost opportunity costs for nonsynchronized reserve. Offline units cannot be dispatched to provide energy, because PJM has not called them to come online, so they do not have a lost opportunity to provide energy. As a result, the supply curve for nonsynchronized reserve has a price of zero and there are no 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 than synchronized reserve, 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

There is no explicit demand for non-synchronized reserve beyond a more general demand for primary reserve, which can be satisfied by the synchronized and nonsynchronized reserve products, and for 30-minute reserve, which can be satisfied by all three reserve products. Beyond the synchronized reserve requirement, the balance of primary reserve can be made up by the most economic combination of synchronized and nonsynchronized reserve. While it can be used to fill the 30-minute reserve requirement, as seen in Figure 10-1, nonsynchronized reserve is mainly used for satisfying the primary reserve requirement.

In the RTO Zone, in the first three months of 2023, the average real-time scheduled nonsynchronized reserve was 839.8 MW and the average day-ahead scheduled nonsynchronized reserve was 1,326.4 MW. In the MAD Subzone, in the first three months of 2023, the average real-time scheduled nonsynchronized reserve was 188.7 MW and the average day-ahead scheduled nonsynchronized reserve was 437.9 MW.

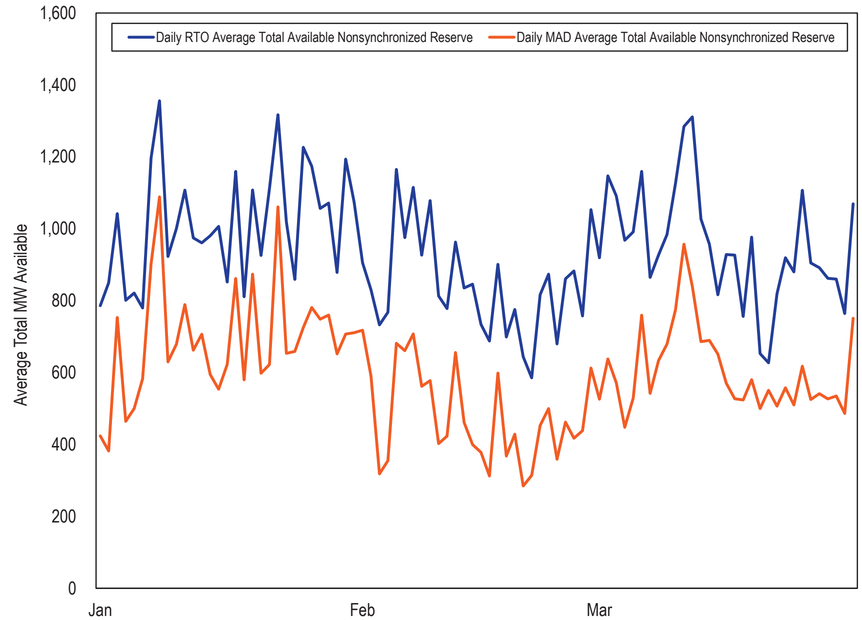
Supply

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 made themselves unavailable or have defined themselves to be emergency only will not be considered. Resources that generally qualify as nonsynchronized reserve include run of river hydro, pumped hydro, combustion turbines, diesels, and combined cycles that can start in 10 minutes or less.

The available reserve MW for nonsynchronized reserve units is the lesser of the economic maximum or the ramp rate times 10 minutes minus the startup and notification time. Hydroelectric resources must separately specify their availability and offer MW.

In the first three months of 2023, an average of 839.4 MW of nonsynchronized reserve was scheduled per five minute interval out of 940.1 eligible MW as part of the primary reserve requirement in the RTO Zone. Figure 10-10 shows daily average total nonsynchronized reserve MW available in the first three months of 2023.

Figure 10-10 Daily Average Available Nonsynchronized Reserve: January through March, 2023



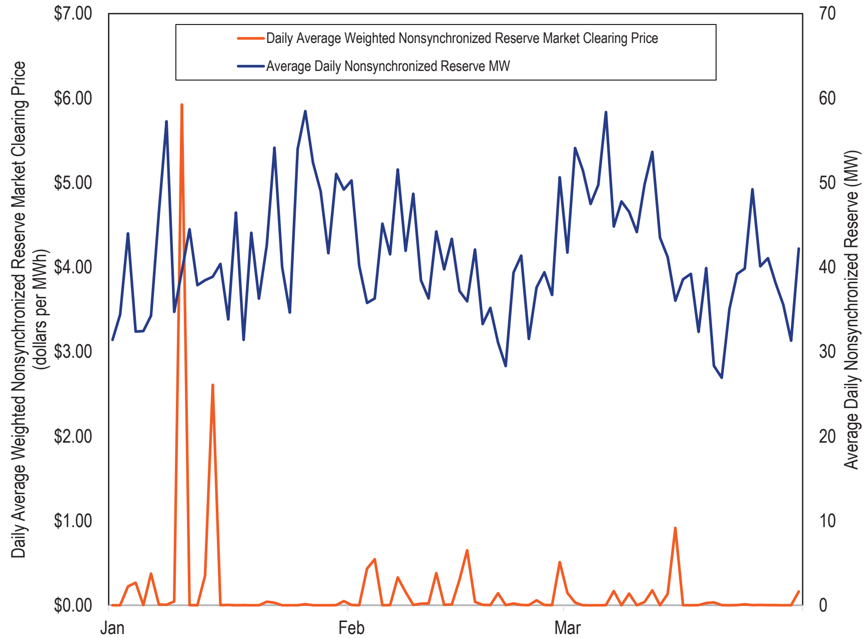
Market Behavior

The offer price for nonsynchronized reserve for all resources is cost based, which is $0 per MWh for all resources.

Market Performance

The settled price of nonsynchronized reserve is calculated in real time every five minutes for the RTO Reserve Zone and the MAD Reserve Subzone. Figure 10-11 shows the daily average nonsynchronized reserve market clearing price (NSRMCP) and average credited MW for the RTO Zone. In the first three months of 2023, the real-time weighted average nonsynchronized market clearing price for all intervals was $0.18 per MWh and the real-time average nonsynchronized reserve credited was 839.8 MW. The day-ahead weighted average nonsynchronized market clearing price for all intervals was $0.18 per MWh and the day-ahead average nonsynchronized reserve cleared MW was 1,326.4 MW. Shortage pricing for primary reserve in the RTO and MAD was used for 3 intervals on January 10, 2023, causing a spike in the average price.

Figure 10-11 Daily weighted average RTO Zone nonsynchronized reserve market clearing price and MW purchased: January through March, 2023



The price of nonsynchronized reserve in most intervals of the first three months of 2023 was $0 per MWh. Table 10-18 shows the number of five-minute intervals with a market clearing price above $0 per MWh. The day-ahead market clears by hour, equivalent to blocks of 12 five-minute intervals. There were 25,908 five-minute intervals in the first three months of 2023.

Table 10-18 Number of five-minute intervals with NSRMCP above $0 per MWh: January through March, 2023

Location	Market	Number of Intervals Where NSRMCP Above $0 per MWh	Percent of Intervals Where NSRMCP Above $0 per MWh
RTO	RT	4,980	19.2%
RTO	DA	2,808	10.8%
MAD	RT	5,134	19.8%
MAD	DA	2,964	11.4%

Table 10-19 shows the effect of fast start pricing on the nonsynchronized reserve market's monthly weighted average market clearing price since October 2022. For the real-time market, these are the LPC prices weighted by the RT SCED MW. For the day-ahead values, these are the DA prices weighted by the DA dispatch MW. The prices being compared include the RTO Reserve Zone prices and the reserve subzone prices. The weighted average market clearing price for each month is consistently higher in the pricing run than in the dispatch run. In the first three months of 2023, the weighted average real-time price from the pricing run was 2.7 percent lower than the weighted average real-time price from the dispatch run. In the first three months of 2023, the weighted average day-ahead price from the pricing run was 4.0 percent higher than the weighted average day-ahead price from the dispatch run.

Table 10-19 Comparison of fast start and dispatch pricing components: October 2022 through March 2023

		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	$0.11	$0.11	$0.00	3.2%	$0.01	$0.08	$0.08	1,033.6%
2022	Nov	$0.48	$0.51	$0.02	5.1%	$0.01	$0.01	$0.00	47.4%
2022	Dec	$0.29	$0.30	$0.01	3.9%	$5.14	$4.85	($0.29)	(5.7%)
2023	Jan	$0.07	$0.07	$0.00	4.0%	$0.31	$0.32	$0.01	4.6%
2023	Feb	$0.08	$0.08	($0.00)	(0.0%)	$0.10	$0.15	$0.05	46.0%
2023	Mar	$0.08	$0.08	$0.00	3.6%	$0.03	$0.06	$0.03	94.3%

In the first three months of 2023, the weighted average price of nonsynchronized reserve was $0.18 per MWh and the weighted average credit for nonsynchronized reserve was -$0.03 per MWh. This negative value for the weighted average credit for the first three months of 2023 is due to nonsynchronized reserve resources clearing more MW in the day-ahead market than in the real-time market, leading to negative total balancing MCP credits. (See Table 10-20 and Table 10-21.)

Table 10-20 shows the total nonsynchronized reserve payments by month from October 2022 through March 2023. During Winter Storm Elliot in December 2022, 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 10-20 Total nonsynchronized payments and charges by month: October 2022 through March 2023

Year	Month	Day-Ahead Credits	Real-Time and Balancing MCP Credits	LOC Credits	Shortfall Charges	Total Credits
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	($24,704,387)	$604,197	NA	($23,807,353)
2023	Jan	$73,610	($155,466)	$4,850	NA	($77,007)
2023	Feb	$72,133	($113,200)	$31,094	NA	($9,973)
2023	Mar	$72,194	($37,214)	$3,368	NA	$38,348

Table 10-21 provides the day-ahead and real-time nonsynchronized reserve by resource type and fuel type for the first three months of 2023. As seen in the table, except for run-of-river hydro units, almost all unit types cleared less MW in the real-time market than in the day-ahead market.

Table 10-21 Day-ahead and real-time nonsynchronized reserve by resource type and fuel type: January through March, 2023

Resource / Fuel Type	Day-Ahead MWh	Real-Time Scheduled MWh	Day-Ahead Credits	Balancing MCP Credits	LOC Credits	Total Credits
CT - Oil	669,906	522,964	$156,581	($13,145)	$7,503	$150,939
Hydro - Run of River	0	277,573	$0	$25,453	$0	$25,453
CT - Other	6,477	4,584	$1,487	($25)	$0	$1,462
RICE - Oil	4,318	2,794	$991	($0)	$0	$991
RICE - Other	926	29	$151	($429)	$0	($278)
CT - Natural Gas	308,739	0	$58,727	($111,326)	$2,697	($49,903)
Hydro - Pumped Storage	1,811,336	918,517	$0	($206,408)	$29,112	($177,296)
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

30-Minute Reserve

The 30-minute reserve service is provided by resources that can respond in 30 minutes. In addition to the reserve products used to satisfy the primary reserve requirement, the 30-minute reserve requirement can also be satisfied by the secondary reserve product. PJM defines secondary reserve as reserves (online or offline available for dispatch) that can be converted to energy in 10 to 30 minutes. There is no NERC standard for secondary reserve or for 30-minute reserve. The secondary reserve product can only be used to satisfy the 30-minute reserve requirement, and it is cleared for five minute intervals in real time and sixty minute intervals day ahead. Failure to convert offline secondary reserves to energy at PJM's request results in a shortfall charge.

Market Structure

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.[63] Unlike with synchronized reserve and primary reserve, PJM does not model a 30-minute reserve requirement for the defined reserve subzone.[64] 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 first three months of 2023.

In the first three months of 2023, the average real-time 30-minute requirement was 3,206.3 MW and the average day-ahead 30-minute requirement was 3,206.3 MW (Figure 10-1).

Supply

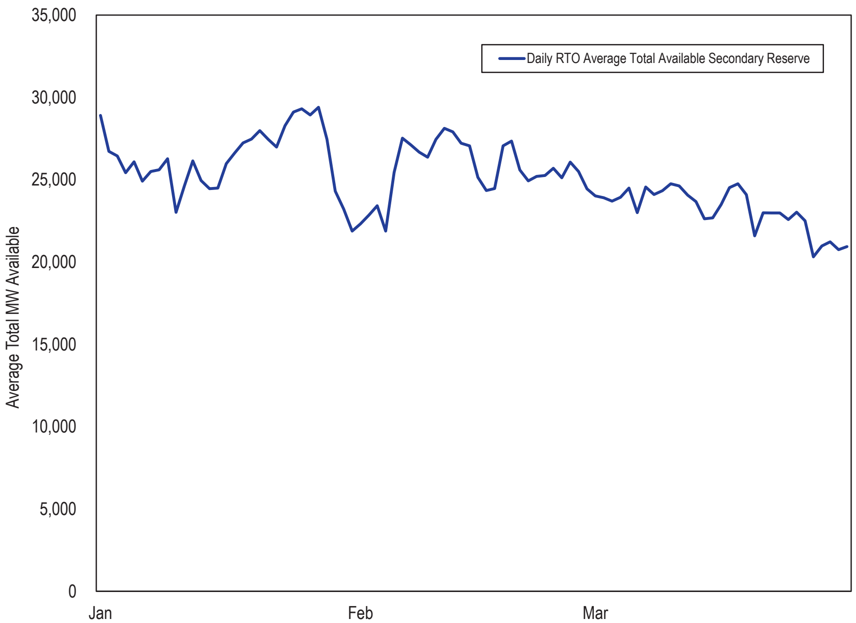
The supply of 30-minute reserves includes all primary reserves plus any synchronized or offline reserves that can convert to energy in 30 minutes. In addition to synchronized reserves and nonsynchronized reserves, the 30-minute reserve requirement can also be satisfied using secondary reserves. Secondary 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. Secondary reserves do not include pre-emergency or emergency demand response resources, even if they offer to start in 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 reserve can only be used to help satisfy the 30-minute reserve requirement. As with the other reserve products, for most resources, PJM determines the MW available for secondary reserve based on energy offer parameters.[65] Energy storage resources, hydroelectric resources, and demand response resources must specify their availability and MW separately. 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.[66] The use of the secondary reserve maximum output limit requires prior approval by PJM.[67] 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.[68]

Figure 10-12 shows the daily average total available secondary reserve in the first three months of 2023. In the first three months of 2023, the average real-time supply of secondary reserve was 25,010 MW.

63 See PJM. "PJM Manual 11: Energy & Ancillary Services Market Operations" § 4.3 Reserve Requirement Determination, Rev. 122 (Oct. 1, 2022).
64 See PJM. "PJM Manual 11: Energy & Ancillary Services Market Operations" § 4.3.1 Locational Aspect of Reserves, Rev. 122 (Oct. 1, 2022).
65 See PJM. "PJM Manual 11: Energy & Ancillary Services Market Operations" § 4.2.3 Reserve Market Resource Offer Structure, Rev. 122 (Oct. 1, 2022).
66 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).
67 See PJM. "PJM Manual 11: Energy & Ancillary Services Market Operations" § 4.2.2.1 Communication for Reserve Capability Limitation, Rev. 122 (Oct. 1, 2022).
68 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 10-12 Daily Average Available Secondary Reserve: January through March, 2023



Market Concentration

Table 10-22 shows the average HHI of the 30-minute reserve market, including synchronized, nonsynchronized, and secondary reserves, and the percent of intervals for which the maximum market share is above 20 percent. In the first three months of 2023, the RTO Zone was unconcentrated in the day-ahead and real-time markets.

Table 10-22 PJM 30-minute reserve market HHI: January through March, 2023

Location	Market	Average HHI	Percent of Intervals Max Market Share Above 20%
RTO	RT	881	29.2%
RTO	DA	439	0.1%

Market Behavior

The offer price for secondary reserve for all resources is cost based, which is $0 per MWh for offline resources. For online resources, the energy market opportunity cost is calculated by PJM based on market prices.

Market Performance

Figure 10-13 provides the prices for secondary reserves for the first three months of 2023. In the first three months of 2023, the secondary reserve market clearing price in the real-time and day-ahead markets was always $0 per MWh.

Figure 10-13 Secondary reserve prices: January through March, 2023

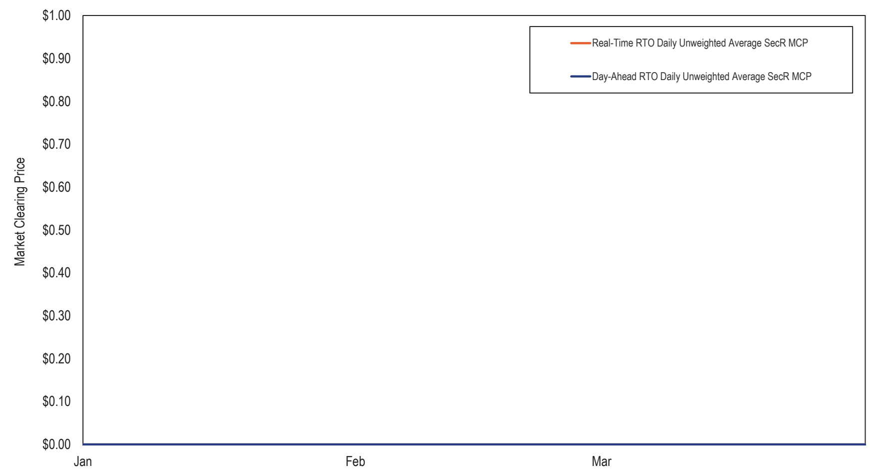


Table 10-23 compares the dispatch-run and pricing-run market clearing prices for the day-ahead and real-time secondary reserve markets. For the real-time values, these are the LPC prices weighted by the RT SCED MW. For the day-ahead values, these are the DA prices weighted by the DA dispatch MW. In the first three months of 2023, 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 otherwise.

Table 10-23 Comparison of fast start and dispatch pricing components: October 2022 through March 2023

		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	NA	$0.52	$0.53	$0.01	1.0%
2023	Jan	$0.00	$0.00	$0.00	NA	$0.00	$0.00	$0.00	NA
2023	Feb	$0.00	$0.00	$0.00	NA	$0.00	$0.00	$0.00	NA
2023	Mar	$0.00	$0.00	$0.00	NA	$0.00	$0.00	$0.00	NA

Table 10-24 shows the day-ahead credits, balancing market credits, LOC credits, and effective shortfall charges for secondary reserves from October 2022 through March 2023.[69] Because the market clearing price for secondary reserve was always $0.00 per MWh in the first three months of 2023, the only credits paid during the first three months of 2023 were LOC credits for resources with non-zero LMPs. In the first three months of 2023, the weighted average secondary reserve market clearing price was $0.00 per MWh. In the first three months of 2023, the weighted average credit per MWh, considering the total credits paid and the capped MWh, was $0.01 per MWh.

During Winter Storm Elliott in December 2022, secondary reserve positions were converted to energy in real-time, resulting in negative balancing credits and offsetting LOC credits. All intervals with non-zero shortfall charges for secondary reserve occurred during Winter Storm Elliott.

Table 10-24 Monthly secondary reserve settlements: October 2022 through March 2023

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	$11,744	$0	$11,744
2022	Dec	$0	($3,877,100)	$3,670,094	$41,440	($207,006)
2023	Jan	$0	$0	$5,150	$0	$5,150
2023	Feb	$0	$0	$34,129	$0	$34,129
2023	Mar	$0	$0	$12,363	$0	$12,363

69 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 10-25 provides secondary reserve credits by resource type for the first three months of 2023.

Table 10-25 Secondary reserve credits by resource type: January through March, 2023

Resource / Fuel Type	Day-Ahead MWh	Real-Time Capped MWh	Day-Ahead Credits	Balancing MCP Credits	LOC Credits	Total Credits
CT - Natural Gas	27,361,496	4,052,284	$0	$0	$42,600	$42,600
CT - Oil	3,606,556	558,061	$0	$0	$6,294	$6,294
Combined Cycle	7,111	8,914	$0	$0	$1,053	$1,053
Steam - Coal	2,234	12,295	$0	$0	$860	$860
RICE - Other	7,388	1,024	$0	$0	$358	$358
Steam - Natural Gas	85	278	$0	$0	$182	$182
RICE - Natural Gas	215,230	12,847	$0	$0	$179	$179
Hydro - Run of River	0	11,156	$0	$0	$92	$92
Steam - Other	24	28	$0	$0	$25	$25
CT - Other	6,475	57	$0	$0	$0	$0
Hydro - Pumped Storage	0	270	$0	$0	$0	$0
RICE - Oil	160,419	7,255	$0	$0	$0	$0
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
Steam - Oil	0	0	NA	NA	NA	NA
Wind	0	0	NA	NA	NA	NA
Wind + Storage	0	0	NA	NA	NA	NA

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.[70] 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.

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.

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

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.[71] Performance scores are reported on an hourly basis for each resource.

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

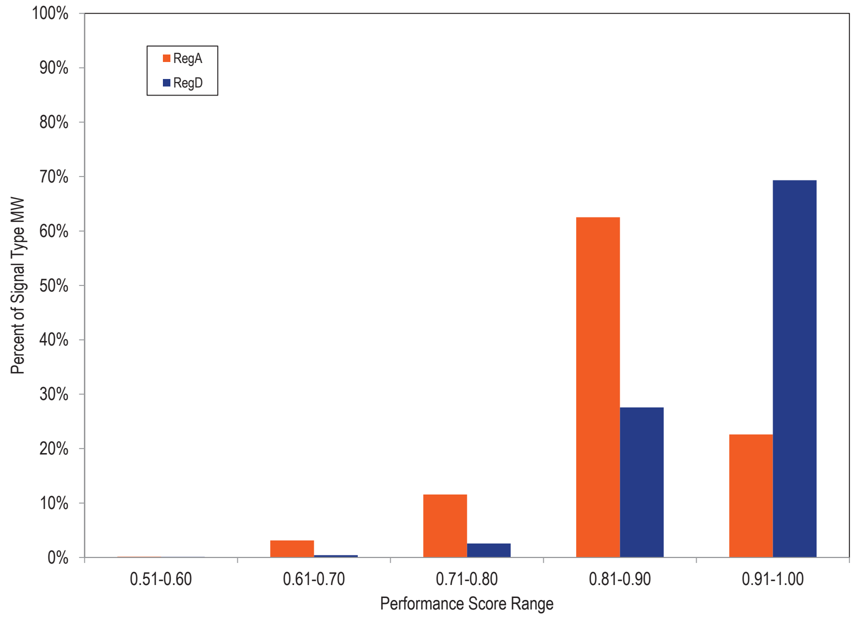
Table 10-26 and Figure 10-14 show the average performance score by resource type and the signal followed in the first three months of 2023. In these figures, the MW used are actual MW and the performance score is the hourly performance score of the regulation resource.[72] Each category (color bar) is based on the percentage of the full performance score distribution for each resource (or signal) type. As Figure 10-14 shows, 69.3 percent of RegD resources had average performance scores within the 0.91-1.00 range, and 22.6 percent of RegA resources had average performance scores within that range in the first three months of 2023. In the first three months of 2022, 81.2 percent of RegD resources had average performance scores within the 0.91-1.00 range, and 16.2 percent of RegA resources had average performance scores within that range.

Table 10-26 Hourly average performance score by unit type: January through March, 2023

		Performance Score Range				
		51-60	61-70	71-80	81-90	91-100
RegA	Battery	-	-	-	-	-
	CT	0.0%	0.0%	2.5%	60.7%	36.8%
	Diesel	0.0%	0.0%	0.0%	15.7%	84.3%
	DSR	0.0%	0.0%	100.0%	0.0%	0.0%
	Hydro	0.0%	0.0%	0.2%	50.4%	49.4%
	Steam	0.2%	4.4%	16.3%	67.7%	11.2%
RegD	Battery	0.1%	0.0%	0.2%	26.9%	72.7%
	CT	0.0%	0.0%	9.8%	64.9%	25.3%
	Diesel	0.0%	0.0%	3.6%	53.4%	42.9%
	DSR	0.0%	0.1%	19.7%	26.4%	53.7%
	Hydro	0.0%	18.1%	0.0%	39.4%	42.5%
	Steam	-	-	-	-	-

72 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: January through March, 2023



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 10-27). 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 10-27 Seasonal regulation requirement definitions[73]

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

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.[74] 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.[75] Table 10-28 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

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

74 See FERC Docket Nos. EL17-64-000 and EL17-65-000.

75 See 170 FERC ¶ 61,258 (2020).

additional regulation credits received as a result of the settlement, from July 2020 through the first three months of 2023, are shown in Table 10-29. From July 2020 through the first three months of 2023, the battery settlement has provided $4.0 million in excess regulation credits.

Table 10-28 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 10-29 Excess regulation credits received by settlement batteries: July 2020 through March, 2023

Year	Month	Excess Regulation Credit ($)
2020	Jul	$49,068
	Aug	$39,863
	Sep	$26,064
	Oct	$56,734
	Nov	$55,966
	Dec	$52,532
	Total	$280,226
2021	Jan	$40,752
	Feb	$82,768
	Mar	$76,248
	Apr	$61,786
	May	$65,797
	Jun	$60,896
	Jul	$76,253
	Aug	$136,365
	Sep	$112,929
	Oct	$156,829
	Nov	$213,585
	Dec	$118,995
	Total	$1,203,204
2022	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
2023	Jan	$83,125
	Feb	$76,978
	Mar	$83,153
	Total	$243,256

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.[76] 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 10-30 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 the first three months of 2023, the battery settlement resulted in customers paying $18,454 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 the first three months of 2023 over paid for regulation by $261,710 (the sum of Table 10-29 and Table 10-30).

Table 10-30 Excess payments and monthly additional MW cleared due to battery settlement: January 2022 through March 2023

		Battery Settlement Impact	
Year	Month	Regulation Credits	Additional Cleared Regulation MW
2022	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
2023	Jan	$10,985	47.5
	Feb	$1,495	122.7
	Mar	$5,974	334.9
	Total	$18,454	505.1

76 See *id.* at P 17.

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.[77]

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.[78]

77 The MBF, as used in this report, refers to PJM's incorrectly calculated MBF and not the MBF equivalent to the MRTS.
78 162 FERC ¶ 61,295 (2018), *reh'g denied*, 170 FERC ¶ 61,259 (2020).

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 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.[79] 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.

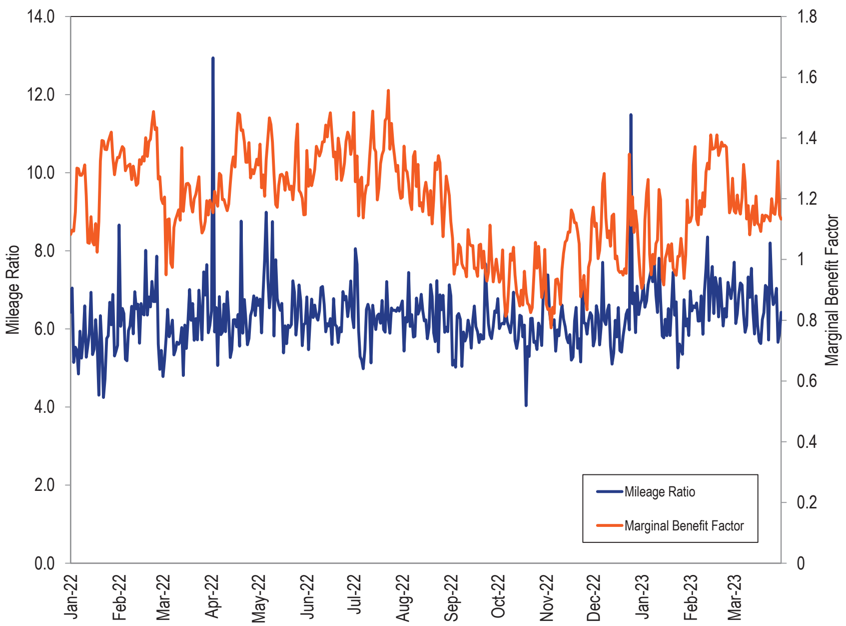
The change in design decreased RegA mileage (the change in MW output in response to regulation signal per MW of capability), increased the proportion of cleared RegD resources' capability that was called by the RegD signal (increased REG for a given MW) to better match offered capability, increased the 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 increased from 6.05 in the first three months of 2022, to 6.62 in the first three months of 2023 (an increase of 9.5 percent). The average MBF decreased from 1.24 in the first three months of 2022, to 1.16 in the first three months of 2023 (a decrease of 6.7 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.

79 145 FERC ¶ 61,011 (2013).

Figure 10-15 Daily average MBF and mileage ratio: January 2022 through March 2023



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.

Table 10-31 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, 2022, through March 31, 2022. The average regulation market clearing price in the first three months of 2023 was $27.40 higher than in the first three months of 2022 (See Table 10-45.) In the first three months of 2023, RegD resources earned 28.6 percent more per performance adjusted actual MW than RegA resources (17.4 percent in the first three months of 2022) due to the inclusion of the mileage ratio in RegD MW settlement.

Table 10-31 Average monthly price paid per performance adjusted actual MW of RegD and RegA: January 2022 through March 2023

		Settlement Payments		
Year	Month	RegD ($/Performance Adjusted MW)	RegA ($/Performance Adjusted MW)	Percent RegD Overpayment ($/Performance Adjusted MW)
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%
2023	Jan	$21.52	$17.01	26.6%
	Feb	$21.57	$15.49	39.2%
	Mar	$20.50	$16.82	21.9%
Total		$21.19	$16.47	28.6%

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 the first three months of 2023 (1.16).

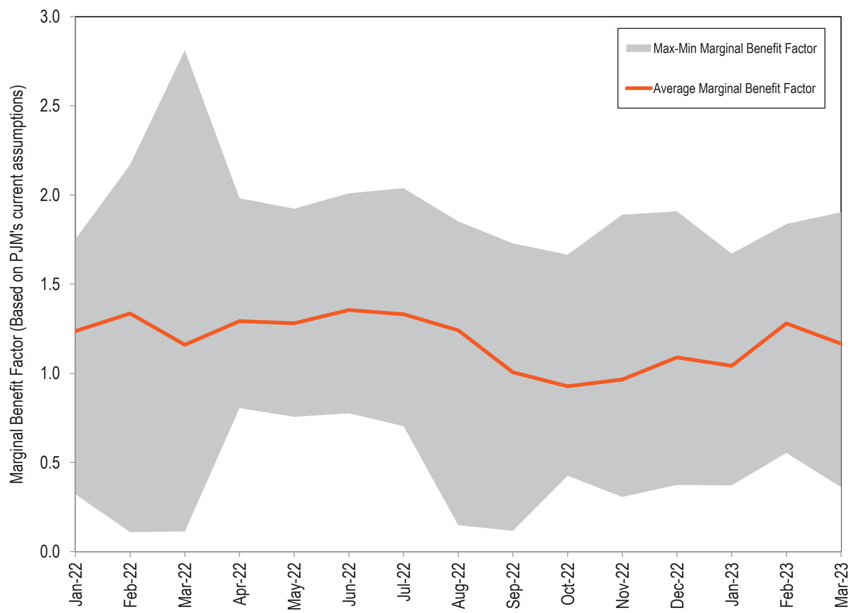
The effect of using the mileage ratio instead of the MBF for purposes of settlement is illustrated in Table 10-32. Table 10-32 shows how much RegD resources are currently being paid, adjusted to a per effective MW basis, on average, in 2022 and the first three months of 2023 under the current rules, 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 the first three months of 2023, the MBF averaged 1.16, while the average daily mileage ratio was 6.62, resulting in RegD resources being paid $242,746 more than they would have been paid on an effective MW basis if the MBF were correctly implemented. In the first three months of 2022, the MBF averaged 1.24, and the average mileage ratio was 6.05, resulting in RegD resources being paid $1.82 million less than they would have been paid if the MBF were correctly implemented. The shift from underpayment to overpayment of RegD resources between the first three months of 2022 and the first three months of 2023 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 10-32 Average monthly price paid per effective MW of RegD and RegA under mileage and MBF based settlement: January 2022 through March 2023

		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 ($)
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	$51.12	(0.8%)	($8,033,848)
2023	Jan	$22.25	$17.01	$17.01	30.9%	$293,915
	Feb	$16.90	$15.49	$15.49	9.1%	$63,924
	Mar	$17.10	$16.82	$16.82	1.7%	($115,093)
Total		$18.81	$16.47	$16.47	14.2%	$242,746

Figure 10-16 shows, the monthly maximum, minimum and average MBF, for January 2022 through March 2023. The average daily MBF in the first three months of 2023 was 1.16. The average daily MBF in the first three months of 2022 was 1.24. The bottom of the MBF range results from PJM's administratively defined MBF minimum threshold of 0.1. The increase in the maximum and average MBF compared to previous years 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 2022 through March 2023



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.[80]

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 10-33 shows, by month, cleared RegD MW with an effective price of $0.00 (units with zero offers plus self scheduled units) for January 2022 through March 2023. In the first three months of 2023, an average of 97.5 percent of all RegD MW clearing the market had an effective offer of $0.00. In the first three months of 2022, an average of 97.3 percent of all cleared RegD MW had an effective cost of $0.00. In the first three months of 2023, an average of 58.2 percent of all RegD offers were self scheduled, compared to an average of 59.7 percent of all RegD offers in the first three months of 2022.

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 increased 6.5 MW (4.3 percent), from 152.2 MW in the first three months of 2022 to 158.7 MW in the first three months of 2023. The average monthly RegD cleared with an effective cost of zero increased 6.8 MW (4.6 percent), from 148.0 MW in the first three months of 2022 to 154.8 MW in the first three months of 2023. Self scheduled RegD cleared MW increased 1.7 MW (1.9 percent), from 91.0 MW in the first three months of 2022 to 92.7 MW in the first three months of 2023. Average cleared RegD MW with a zero cost offer increased 5.1 MW (8.9 percent), from 57.1 MW in the first three months of 2022 to 62.2 MW in the first three months of 2023. 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.

80 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 10-33 Average cleared RegD MW and average cleared RegD with an effective price of $0.00 by month: January 2022 through March 2023

		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
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
2023	Jan	56.6	33.4%	110.5	65.2%	167.1	98.5%	169.6
	Feb	66.6	43.0%	82.9	53.5%	149.5	96.6%	154.8
	Mar	63.3	41.7%	84.7	55.8%	147.9	97.4%	151.8
Total		62.0	39.0%	93.0	58.6%	155.0	97.6%	158.9

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.

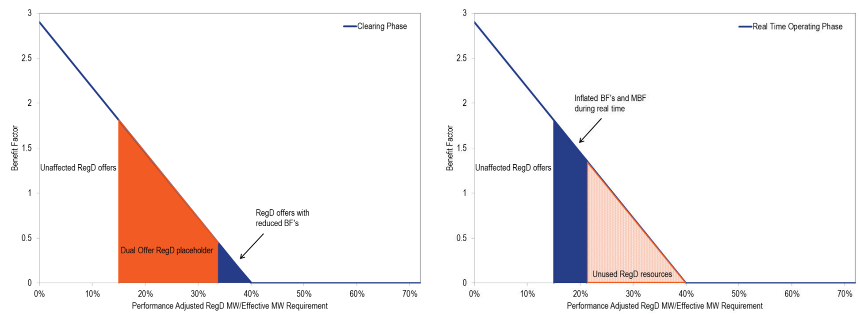
Each dual offer resource is assigned to run as either a RegD or RegA resource based on which of the two offers has a lower effective cost. But PJM does not redefine the supply curve using appropriately recalculated unit specific benefit factors for the remaining RegD resources prior to clearing the market.

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.

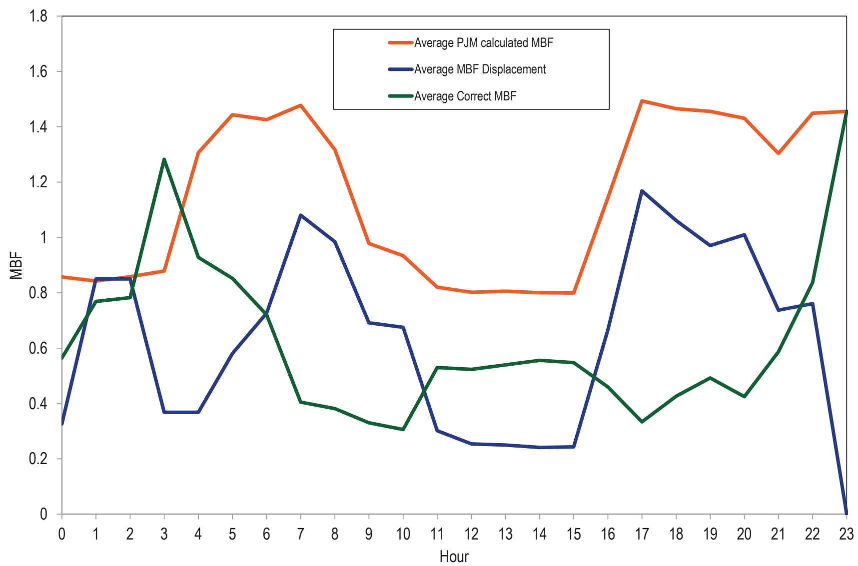
The issue is illustrated in Figure 10-17. The example shows a clearing phase and a real time operating phase. In this example, a 150 MW unit offers both RegA and RegD. The 150 MW unit's position in the RegD effective cost curve and the potential effective MW are represented as the orange area under the 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 the first three months of 2023, all hours had at least one unit with a dual offer. In the first three months of 2023, 50.7 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 0.76 in the operating phase. The average MBF increase due to dual offers clearing as RegA in the first three months of 2022 was 0.75. 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 the first three months of 2023. In the first three months of 2023, 3,124 dual offers from generating units were cleared as RegA, an increase of 98.9 percent from the first three months of 2022 (1,571 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 the first three months of 2023 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: January through March, 2023



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.

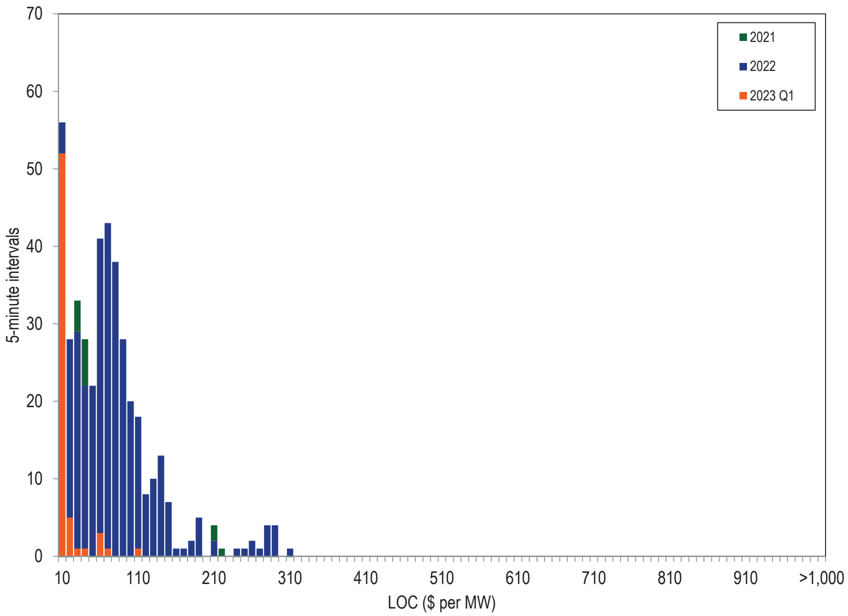
The regulation market is cleared on an hour ahead basis, using offers that are adjusted by dividing each component of an offer (capability, performance, and lost opportunity cost) by the product of the unit specific benefit factor and unit specific performance score. To calculate the hour ahead estimate 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.[81] 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 2021 through the first three months of 2023.

81 See 166 FERC ¶ 61,040 (2019).

Figure 10-19 LOC distribution in each five minute interval with a RegD marginal unit and an LOC greater than zero: 2021 through March 2023



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.

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.[82] 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.[83] 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 10-34 shows the amount of uplift overpayment by fuel type for the first three months of 2023, 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 the first three month of 2023, overpayments totaled $2.5 million. Coal units received 45.5 percent of the overpayment while providing 2.7 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.

82 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.

83 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 10-34 Amount of LOC overpayment: January 2022 through March 2023

		Uplift Overpayment		
Year	Month	Coal	Natural Gas	Total
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
2023	Jan	$219,632	$409,362	$628,995
	Feb	$304,776	$399,282	$704,058
	Mar	$606,703	$547,406	$1,154,109
Total		$1,131,111	$1,356,050	$2,487,162

Winter Storm Elliott

During emergency events, PJM has the authority to suspend all regulation assignments.[84] During such suspensions and for ten minutes after the end of the event, performance scores for regulating resources are not calculated.[85] 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.

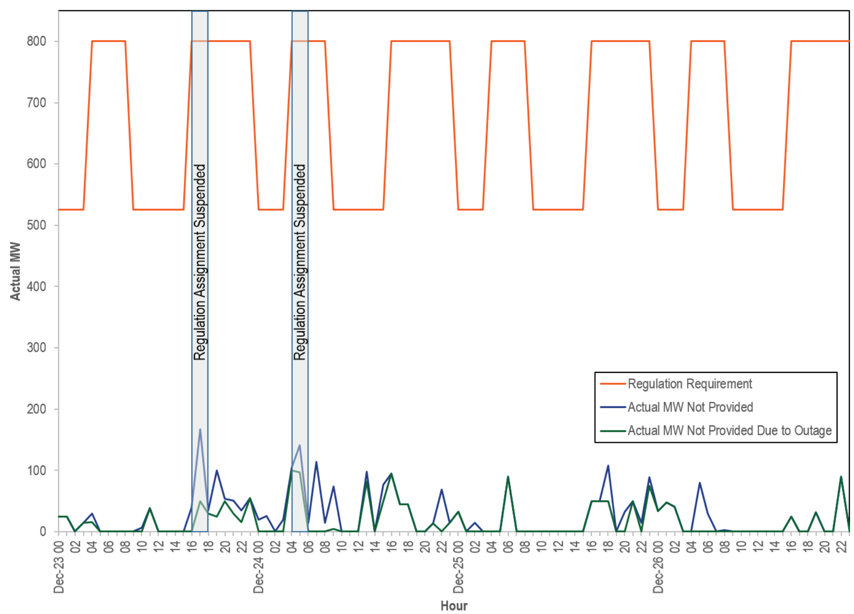
In addition, multiple units were committed for regulation in the hour ahead clearing, but did not provide regulation in real time. Figure 10-20 shows the amount of regulation actual MW that were committed, but did not provide

84 See "PJM Manual 13: Emergency Operations," § 2.3.2, Rev. 86 (Nov. 03, 2022).

85 See "PJM Manual 12: Balancing Operations," § 4.4.8, Rev. 47 (Oct. 01, 2022).

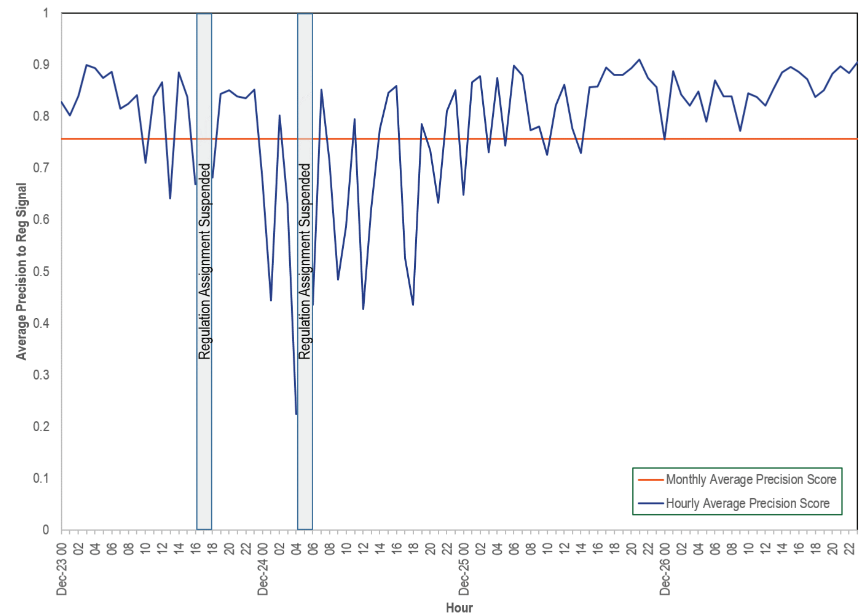
regulation in real time, and the committed MW that did not provide regulation due to an outage. An hourly average of 26.7 MW were committed but did not provide regulation from December 23 through December 26. Of the average shortfall, an average of 16.5 MW was the result of unit outages.

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 10-21 shows the average hourly precision score of all battery units in operation, from December 23 through December 26, as well as the average precision score for the rest of the month (December 1 through December 22; December 27 through 31) of all battery units for December 2022.[86]

Figure 10-21 Average hourly and rest of month RegD precision score of battery units



The overall effect of Elliot on units in the regulation market can be seen in Figure 10-22, where the average precision score of each unit type during the event is compared to the average precision score during the rest of December 2022. With the exception of hydro units, all unit types had a drop in their average precision score as a result of outages during the event, being committed in the hour ahead clearing and then not providing regulation in real time, and/or sustained (pegged) signals the units could not maintain.

86 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.

Table 10-35 Average precision score by unit type during Winter Storm Elliot and the rest of December 2022

	Average Precision Score		
Unit Type	Rest of Month (Dec. 1-22; 27-31)	Winter Storm Elliot (Dec. 23-26)	Percent Change
Battery	84.8%	80.5%	(4.3%)
Coal	56.2%	54.7%	(1.5%)
Hydro	85.9%	86.3%	0.4%
Natural Gas	75.3%	71.5%	(3.8%)
DR	70.9%	62.5%	(8.4%)

Market Structure

Supply

Table 10-36 shows average hourly offered MW (actual and effective), and average hourly cleared MW (actual and effective) for all hours in the first three months of 2023.[87] 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.[88] 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 the first three months of 2023, the average hourly offered supply of regulation for nonramp hours was 687.2 actual MW (709.1 effective MW). This was a decrease of 93.5 actual MW (a decrease of 70.9 effective MW) from the first three months of 2022, when the average hourly offered supply of regulation was 780.8 actual MW (780.0 effective MW). In the first three months of 2023, the average hourly offered supply of regulation for ramp hours was 1,043.4 actual MW (1,059.1 effective MW). This was a decrease of 103.8 actual MW (a decrease of 82.4 effective MW) from the first three months of 2022, when the average hourly offered supply of regulation was 1,147.2 actual MW (1,141.6 effective MW).[89] The decrease in the average hourly offered supply actual MW in both ramp and non ramp hours was primarily the result of reduced regulation offers from coal units (Table 10-38). Coal units provide RegA. The decrease in RegA supply resulted in more RegD MW clearing (effective MW greater than actual MW due to RegD MW being multiplied by the benefit factor). This drop in regulation supply from coal is consistent with the significant drop in energy supply from coal units. The energy output of coal units in the first three months of 2023 was down 40.1 percent compared to the first three months of 2022.[90]

The ratio of the average hourly offered supply of regulation to average hourly regulation demand (actual cleared MW) for nonramp hours was 1.45 in the first three months of 2023 (1.67 in the first three months of 2022). The ratio of the average hourly offered supply of regulation to average hourly regulation demand (actual cleared MW) for ramp hours was 1.47 in the first three months of 2023 (1.58 in the first three months of 2022).

87 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.

88 See "PJM Manual 11: Energy & Ancillary Services Market Operations," § 3.2.2 Regulation Market Eligibility, Rev. 124 (April 26, 2023).

89 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.

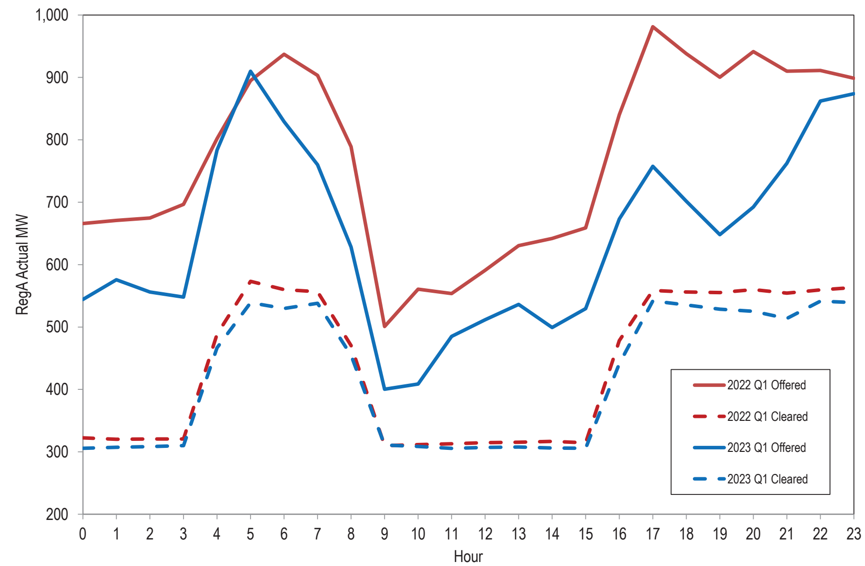
90 See Energy Production by Fuel Source in the 2023 State of the Market Report for PJM, Section 3: Energy Market, Table 3-53.

Table 10-36 Hourly average actual and effective MW offered and cleared: January through March, 2023[91]

			By Resource Type		By Signal Type	
		All Regulation	Generating Resources	Demand Resources	RegA Following Resources	RegD Following Resources
Actual Offered MW	Ramp	1,043.4	1,019.5	23.9	783.8	259.6
	Nonramp	687.2	666.8	20.5	509.0	178.3
Effective Offered MW	Ramp	1,059.1	1,027.1	32.0	681.4	377.7
	Nonramp	709.1	688.1	21.0	438.8	270.3
Actual Cleared MW	Ramp	709.5	685.7	23.7	531.8	177.7
	Nonramp	473.4	453.8	19.7	310.5	162.9
Effective Cleared MW	Ramp	800.1	768.1	31.9	467.9	332.1
	Nonramp	534.8	514.3	20.4	272.2	262.5

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 the first three months of 2023 was 783.8 actual MW, a decrease of 15.0 percent from the first three months of 2022 (922.4 actual MW.) The average hourly offered MW from RegA resources during nonramp hours for the first three months of 2023 was 509.0 actual MW, a decrease of 17.8 percent from the first three months of 2022 (619.5 actual MW). The average hourly cleared MW from RegA resources during ramp hours for the first three months of 2023 was 531.8 actual MW, a decrease of 5.1 percent from the first three months of 2022 (560.6 actual MW). The average hourly cleared MW from RegA resources during nonramp hours for the first three months of 2023 was 310.5 actual MW, a decrease of 1.8 percent from the first three months of 2022 (316.2 actual MW).

Figure 10-22 Average hourly RegA actual MW offered and cleared: January through March, 2022 through 2023[92]



The average hourly offered MW from RegD resources during ramp hours for the first three months of 2023 was 259.6 actual MW, an increase of 15.4 percent from the first three months of 2022 (224.9 actual MW). (Figure 10-24) The average hourly offered MW from RegD resources during nonramp hours for the first three months of 2023 was 178.3 actual MW, an increase of 10.5 percent from the first three months of 2022 (161.3 actual MW) (Figure 10-23). The average hourly cleared MW from RegD resources during ramp hours for the first three months of 2023 was 177.7 actual MW, an increase of 8.5 percent from the first three months of 2022 (163.7 actual MW). The average hourly cleared MW from RegD resources during nonramp hours for the first three months of 2023 was 162.9 actual MW, an increase of 7.4 percent from the first three months of 2022 (151.6 actual MW).

91 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.

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

Figure 10-23 Average hourly RegD actual MW offered and cleared: January through March, 2022 through 2023[93]

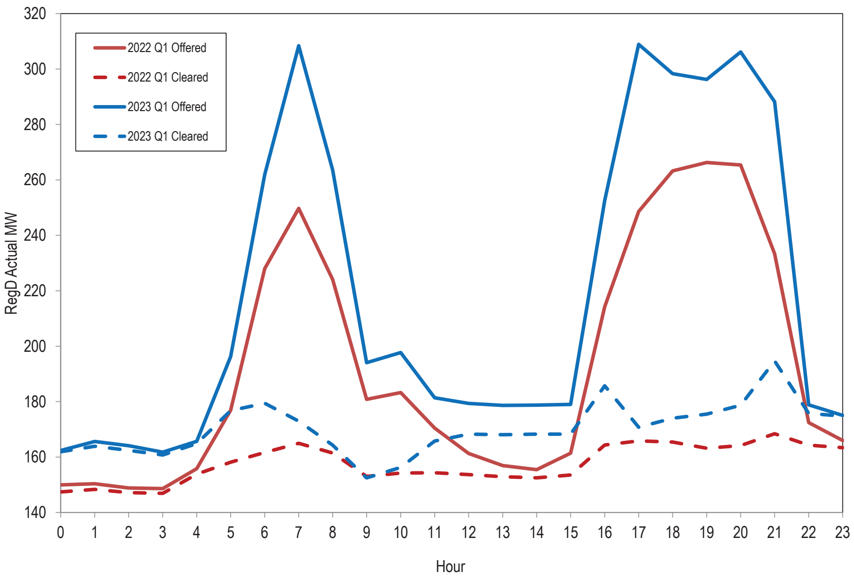


Table 10-37 provides the settled regulation MW by source unit type, the total settled regulation MW provided by all resources, the percent of settled regulation provided by unit type, and the clearing price, uplift, and total regulation credits. In Table 10-37 the MW have been adjusted by the performance score since this adjustment forms the basis of payment for units providing regulation. Total regulation performance adjusted settled MW decreased 0.1 percent from 1,119,076.7 MW in the first three months of 2022 to 1,118,113.7 MW in the first three months of 2023. The average proportion of regulation provided by hydro units increased the most, by 2.2 percent from the first three months of 2022 to the first three months of 2023. Coal units had the largest decrease in average proportion of regulation provided, decreasing 3.6 percent, from the first three months of 2022 to the first three months of 2023. The total regulation credits in the first three months of 2023 were $27,395,836, a decrease of 55.4 percent from $61,415,566 in the first three months of 2022. The decrease in regulation credits is due, in part, to a lower LOC component of regulation prices as a result of lower energy prices in the first three months of 2023 compared to the first three months of 2022.

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 the first three months of 2023 are shown in Table 10-37.

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

Table 10-37 Top 10 recipients of regulation uplift credits: January through March, 2023

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	$1,176,238	21.2%
2	Constellation Energy Generation LLC	PE MUDDY RUN 1-8 H	HYDRO	$1,079,499	19.5%
3	American Electric Power Company Inc	AEP MOUNTAINEER 1 F	COAL	$680,660	12.3%
4	Ontario Power Generation Inc	AP LKLYN 1-4 H	HYDRO	$323,679	5.8%
5	American Municipal Power Inc	FE FREMONT ENERGY CENTER 3 CC	NATURAL GAS	$222,100	4.0%
6	Lotus Infrastructure Partners	PE PHILLIPS ISL LINWOOD 1 CC	NATURAL GAS	$115,275	2.1%
7	American Electric Power Company Inc	AEP AMOS 3 F	COAL	$112,253	2.0%
8	Vistra Energy Corp	COM 935 KENDALL 1 CC	NATURAL GAS	$105,817	1.9%
9	Vistra Energy Corp	COM 935 KENDALL 2 CC	NATURAL GAS	$104,072	1.9%
10	American Electric Power Company Inc	AEP MITCHELL - KAMMER 1 F	COAL	$87,419	1.6%
Total of Top 10				$4,007,011	72.3%
Total Regulation Uplift Credits				$5,545,489	100.0%

The uplift credits received for each unit type are shown in Table 10-38. The total uplift credits received increased 34.1 percent from $8,420,254 in the first three months of 2022 to $5,545,489 in the first three months of 2023. This decrease, like the decrease in total credits, is due in part to lower LOC components of regulation prices and offers as a result of lower energy prices in the first three months of 2023 compared to the first three months of 2022. Hydro units had the largest increase in uplift payments, increasing from $1,297,320 (15.4 percent of total uplift) in the first three months of 2022, to $2,706,801 (48.8 percent of total uplift) in the first three months of 2023.

Table 10-38 PJM regulation by source: January through March, 2022 and 2023[94]

Year	Source	Number of Units	Performance Adjusted Settled Regulation (MW)	Percent of Settled Regulation	Clearing Price Credits	Uplift Credits	Total Regulation Credits
2022	Battery	18	284,398	25.4%	$14,351,654	$0	$14,351,654
	Coal	17	70,382	6.3%	$4,175,594	$2,788,677	$6,964,272
	Hydro	24	243,166	21.7%	$12,588,992	$1,297,320	$13,886,312
	Natural Gas	113	499,599	44.6%	$20,797,332	$4,334,257	$25,131,589
	DR	23	21,532	1.9%	$1,081,740	$0	$1,081,740
Total		195	1,119,076.7	100.0%	$52,995,313	$8,420,254	$61,415,566
2023	Battery	18	288,053	25.8%	$6,284,068	$0	$6,284,068
	Coal	22	30,144	2.7%	$648,657	$1,180,484	$1,829,140
	Hydro	27	267,958	24.0%	$4,889,389	$2,706,801	$7,596,191
	Natural Gas	101	491,125	43.9%	$9,090,638	$1,658,204	$10,748,842
	DR	17	40,834	3.7%	$937,595	$0	$937,595
Total		185	1,118,113.7	100.0%	$21,850,346	$5,545,489	$27,395,836

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

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 10-39).

Table 10-39 Active battery storage projects by submitted year: 2014 through March 2023

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	13	550.1
2019	55	3,609.4
2020	149	9,408.9
2021	309	23,762.1
2022	143	15,723.5
2023	17	1,325.0
Total	692	54,432.0

The supply of regulation can be affected by regulating units retiring from service. If all units that are requesting retirement through the first three months of 2023 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 10-27).

Table 10-40 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 474.7 hourly average performance adjusted actual MW in the first three months of 2023. This is an increase of 9.8 performance adjusted actual MW from the first three months of 2022, when the average hourly total regulation cleared performance adjusted actual MW for nonramp hours were 465.0 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 710.5 hourly average performance adjusted actual MW in the first three months of 2023. This is a decrease of 4.5 performance adjusted actual MW from the first three months of 2022, where the average hourly regulation cleared MW for ramp hours were 715.0 performance adjusted actual MW.[95]

95 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 the first three months of 2023 was 1.16.

Table 10-40 Required regulation and ratio of supply to requirement: January 2022 through March 2023

		Average Required Regulation (MW)		Average Required Regulation (Effective MW)		Ratio of Supply MW to MW Requirement		Ratio of Supply Effective MW to Effective MW Requirement	
Hours	Month	2022	2023	2022	2023	2022	2023	2022	2023
Ramp	Jan	720.6	696.1	800.0	800.1	1.51	1.45	1.37	1.30
	Feb	729.4	715.5	800.0	800.0	1.71	1.48	1.52	1.34
	Mar	723.0	719.9	800.0	800.0	1.54	1.48	1.39	1.35
	Apr	729.3	-	800.0	-	1.47	-	1.34	-
	May	720.2	-	800.0	-	1.54	-	1.38	-
	Jun	714.4	-	800.0	-	1.60	-	1.44	-
	Jul	720.3	-	800.0	-	1.55	-	1.40	-
	Aug	710.9	-	800.0	-	1.60	-	1.43	-
	Sep	704.3	-	800.0	-	1.53	-	1.38	-
	Oct	703.3	-	800.0	-	1.45	-	1.32	-
	Nov	698.8	-	800.0	-	1.43	-	1.29	-
	Dec	705.2	-	798.5	-	1.49	-	1.33	-
Nonramp	Jan	467.4	466.3	525.0	525.3	1.62	1.44	1.45	1.32
	Feb	466.9	494.3	525.0	558.1	1.78	1.50	1.56	1.36
	Mar	468.8	463.6	525.1	525.0	1.63	1.43	1.46	1.31
	Apr	469.1	-	525.1	-	1.56	-	1.41	-
	May	461.5	-	525.3	-	1.60	-	1.43	-
	Jun	459.6	-	525.8	-	1.66	-	1.48	-
	Jul	459.9	-	525.1	-	1.64	-	1.47	-
	Aug	461.3	-	525.3	-	1.65	-	1.48	-
	Sep	465.0	-	525.2	-	1.59	-	1.43	-
	Oct	468.0	-	525.1	-	1.59	-	1.43	-
	Nov	463.5	-	525.5	-	1.52	-	1.38	-
	Dec	468.6	-	525.1	-	1.50	-	1.36	-

Market Concentration

In the first three months of 2023, the effective MW weighted average HHI of RegA resources was 2257 which is highly concentrated and the effective MW weighted average HHI of RegD resources was 1907 which is highly concentrated. The effective MW weighted average HHI of all resources was 1317, 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 10-41 includes a monthly summary of three pivotal supplier (TPS) results. In the first three months of 2022, the three pivotal supplier test was failed in 93.2 percent of hours. The MMU concludes that the PJM Regulation Market in the first three months of 2023 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 10-41 Regulation market monthly three pivotal supplier results: January 2021 through March 2023

	Percent of Hours Pivotal		
Month	2021	2022	2023
Jan	91.4%	94.5%	92.1%
Feb	88.7%	84.1%	91.6%
Mar	87.2%	90.1%	96.0%
Apr	88.5%	92.8%	
May	83.9%	91.4%	
Jun	86.4%	85.7%	
Jul	86.4%	88.2%	
Aug	76.3%	86.4%	
Sep	82.9%	86.1%	
Oct	91.9%	86.7%	
Nov	86.7%	91.0%	
Dec	80.1%	92.2%	
Average	85.9%	89.1%	93.2%

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.[96] 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. Regulation resources are also permitted to change and/or submit intraday offers.[97]

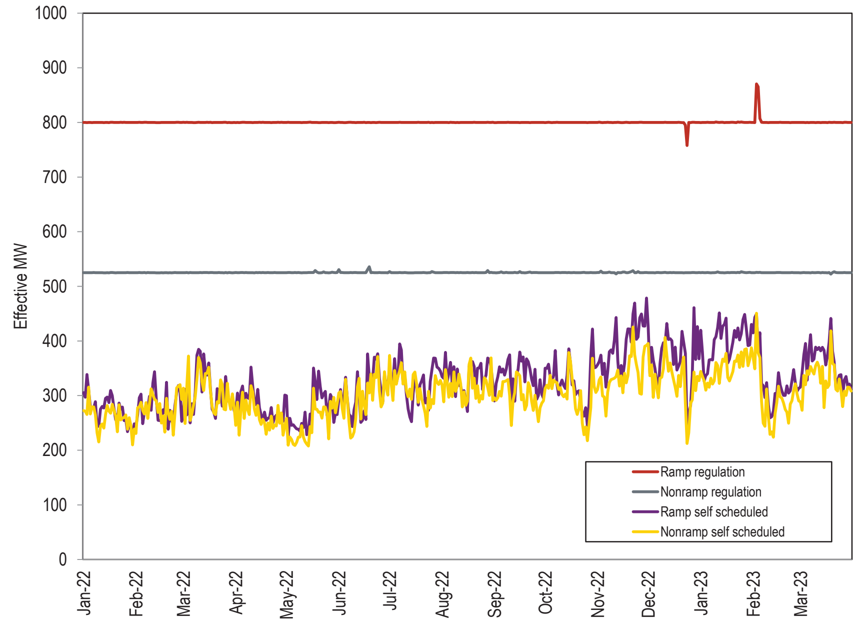
96 See "PJM Manual 11: Energy & Ancillary Services Market Operations," § 3.2.1 Regulation Market Eligibility, Rev. 124 (April 26, 2023).
97 Id. at 3.2.2, at p 62.

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.[98]

Up until 65 minutes 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.[99]

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 10-44).[100] 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 45.3 percent of all effective MW during ramp hours (35.9 percent in the first three months of 2022) and 61.2 percent of all effective MW during nonramp hours (53.5 percent in the first three months of 2022) in the first three months of 2023. Over all hours in the first three months of 2023, self scheduled regulation averaged 51.7 percent of all effective MW (42.9 percent in the first three months of 2022) (See Table 10-42). 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.[101]

Figure 10-24 Nonramp and ramp regulation levels: January 2022 through March 2023



98 See "PJM Manual 15: Cost Development Guidelines," § 7.8 Regulation Cost, Rev. 42 (Oct. 28, 2022).
99 See "PJM Manual 11: Energy & Ancillary Services Market Operations," § 3.2.1 Regulation Market Eligibility, Rev. 124 (April 26, 2023).
100 See "PJM Manual 28: Operating Agreement Accounting," § 4.1 Regulation Accounting Overview, Rev. 90 (Jan. 25, 2023).
101 See "PJM Manual 11: Energy & Ancillary Services Market Operations," § 3.2.1 Regulation Market Eligibility, Rev. 122 (Oct. 1, 2022).

Table 10-42 Total Effective MW and Self Scheduled Effective MW during ramp and non ramp hours: January through March, 2022 and 2023

Year		Effective MW	Self Scheduled Effective MW	Percent Effective MW
2022	Ramp	72,001.0	25,862.5	35.9%
	Non Ramp	47,252.8	25,266.7	53.5%
Total		119,253.9	51,129.3	42.9%
2023	Ramp	72,147.2	32,688.9	45.3%
	Non Ramp	47,261.1	29,282.0	62.0%
Total		119,408.3	61,970.8	51.9%

Table 10-43 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 44.4 percent of the total effective MW in March 2023) and a growing proportion of resources that self schedule (25.0 percent of all self scheduled effective MW in October 2012 and 53.0 percent of all self scheduled effective MW in March 2023). In the first three months of 2023, the average RegD percentage of total self scheduled effective MW was 55.9 percent, a decrease of 15.7 percentage points from the first three months of 2022, when the average was 71.6 percent.

Table 10-43 RegD self scheduled regulation by month: January 2022 through March 2023

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
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%
2023	Jan	217.4	312.5	376.5	674.2	57.7%	46.3%
2023	Feb	178.5	293.4	313.7	685.0	56.9%	42.8%
2023	Mar	180.7	284.8	341.1	641.2	53.0%	44.4%
Average		192.2	296.9	343.7	666.8	55.9%	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 10-44 shows monthly data for 2022 and 2023, and Table 10-44 shows annual data for the first three months of 2012 through the first three months of 2023. Table 10-44 and Table 10-45 are based on settled (purchased) MW.

Table 10-44 Regulation sources: spot market and self scheduled purchases: January 2022 through March 2023

Year	Month	Spot Market Regulation (Unadjusted MW)	Self Scheduled Regulation (Unadjusted MW)
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
2023	Jan	126,117.0	197,873.7
2023	Feb	183,580.7	144,902.8
2023	Mar	154,809.4	181,862.7
	Total	464,507.1	524,639.2

Table 10-45 Regulation sources: spot market and self scheduled: January through March, 2012 through 2023

Year (Jan-Mar)	Spot Market Regulation (Unadjusted MW)	Self Scheduled Regulation (Unadjusted MW)
2012	1,510,190.1	485,672.8
2013	1,026,962.9	342,003.1
2014	724,996.3	404,832.1
2015	670,281.4	411,928.8
2016	583,928.2	546,238.8
2017	534,901.2	520,871.7
2018	678,027.7	395,994.0
2019	539,672.1	500,324.0
2020	515,297.0	557,703.5
2021	542,542.7	556,355.1
2022	687,265.9	369,137.6
2023	464,507.1	524,639.2

In the first three months of 2023, DR provided an average of 23.7 MW of regulation per hour during ramp hours (13.5 MW of regulation per hour during ramp hours in the first three months of 2022), and an average of 19.7 MW of regulation per hour during nonramp hours (10.2 MW of regulation per hour during nonramp hours in the first three months of 2022). Generating units supplied an average of 685.7 MW of regulation per hour during ramp hours in the first three months of 2023 (710.8 MW of regulation per hour during ramp hours in the first three months of 2022), and an average of 453.8 MW per hour during nonramp hours in the first three months of 2023 (457.6 MW of regulation per hour during nonramp hours in the first three months of 2022).

Market Performance

Price

Table 10-46 shows the regulation price and regulation cost per MW for the first three months of 2009 through the first three months of 2023. The weighted average RMCP for the first three months of 2023 was $17.83 per MW. This is a decrease of $27.40 per MW, or 60.64 percent, from the weighted average RMCP of $45.24 per MW in the first three months of 2022. This decrease in the regulation clearing price was the result of a decrease in energy prices in the first three months of 2023 and the related increase in the opportunity cost component of RMCP.

Table 10-46 Comparison of average price and cost for regulation: January through March, 2009 through 2023

Year (Jan-Mar)	Weighted Regulation Market Price	Weighted Regulation Market Cost	Regulation Price as Percent of Cost
2009	$22.25	$34.06	65.3%
2010	$17.97	$31.24	57.5%
2011	$11.52	$25.03	46.0%
2012	$12.62	$16.75	75.3%
2013	$33.91	$39.36	86.2%
2014	$92.97	$112.30	82.8%
2015	$47.91	$58.23	82.3%
2016	$15.55	$17.92	86.8%
2017	$13.89	$18.47	75.2%
2018	$40.33	$49.60	81.3%
2019	$14.05	$18.49	76.0%
2020	$10.99	$13.91	79.0%
2021	$17.18	$21.01	81.8%
2022	$45.24	$55.64	81.3%
2023	$17.83	$24.20	73.7%

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 10-47 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 March 2023. In the first three months of 2023, fast start pricing increased the average regulation market clearing price by 3.3 percent compared to dispatch pricing.

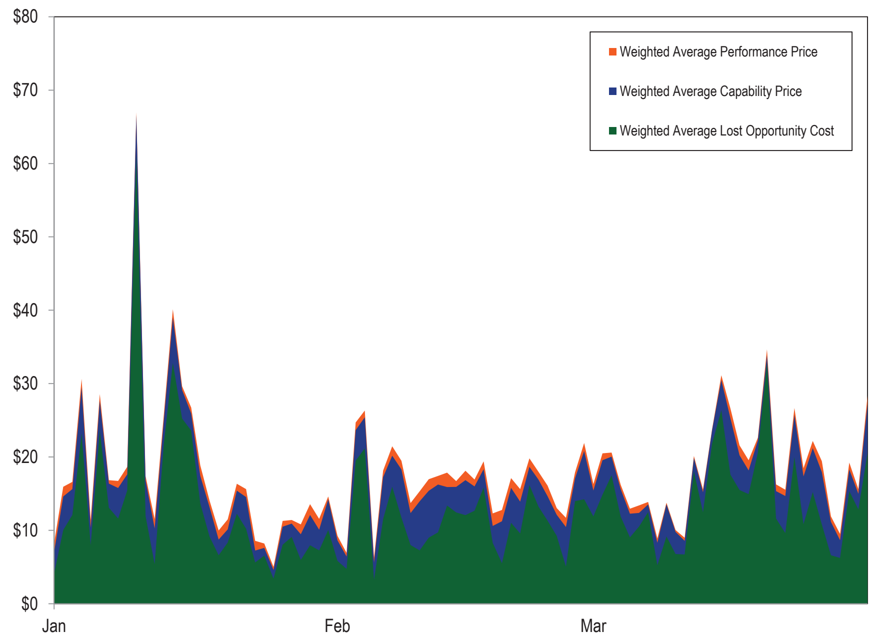
Table 10-47 Comparison of fast start and dispatch pricing: September 2021 through March 2023[102]

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	$112.52	$116.94	$113.81	(2.7%)
Yearly		$48.66	$51.82	$50.37	$53.53	6.3%
2023	Jan	$16.61	$17.25	$17.58	$18.22	3.7%
	Feb	$15.12	$15.48	$16.29	$16.65	2.2%
	Mar	$17.11	$17.80	$17.89	$18.57	3.8%
Total		$16.30	$16.87	$17.27	$17.83	3.3%

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): January through March, 2023



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

Table 10-48 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 10-26 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.

Table 10-48 Regulation market monthly component of price (Dollars per MW): January through March, 2023

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	$17.25	$0.97	$18.22
Feb	$15.48	$1.17	$16.65
Mar	$17.80	$0.77	$18.57
Average	$16.87	$0.97	$17.83

Monthly and total annual scheduled regulation MW and regulation charges, as well as monthly average regulation price and regulation cost are shown in Table 10-49. Total scheduled regulation is based on settled performance adjusted MW. The total of all regulation charges in the first three months of 2023 was $27,446,107 million, compared to $61,421,382 million in the first three months of 2022.

Table 10-49 Total regulation charges: January 2022 through March 2023

Year	Month	Scheduled Regulation (MW)	Total Regulation Charges ($)	Weighted Average Regulation Market Price ($/MW)	Cost of Regulation ($/MW)	Price as Percent of Cost
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	396,206.2	$53,758,750	$113.81	$135.68	83.9%
	Yearly	4,550,354.2	$296,241,818	$53.53	$65.10	82.2%
2023	Jan	393,338.7	$9,812,256	$18.22	$24.95	73.0%
2023	Feb	362,742.5	$8,127,171	$16.65	$22.40	74.3%
2023	Mar	378,020.0	$9,506,681	$18.57	$25.15	73.9%
	Total	1,134,101.3	$27,446,107	$17.83	$24.20	73.7%

The capability, performance, and opportunity cost components of the cost of regulation are shown in Table 10-50. Total scheduled regulation is based on settled performance adjusted MW. In the first three months of 2023, the average total cost of regulation was $24.20 per MW, 55.8 percent lower than $54.76 in the first three months of 2022. In the first three months of 2023, the monthly average capability component cost of regulation was $16.86, 61.3 percent lower than $43.54 in the first three months of 2022. In the first three months of 2023, the monthly average performance component cost of regulation was $2.40, 35.1 percent lower than $3.71 in the first three months of 2022. The decrease of the average total cost in the first three months of 2023 versus the first three months of 2022, was primarily a result of lower LOC values due to higher prices in the energy market.

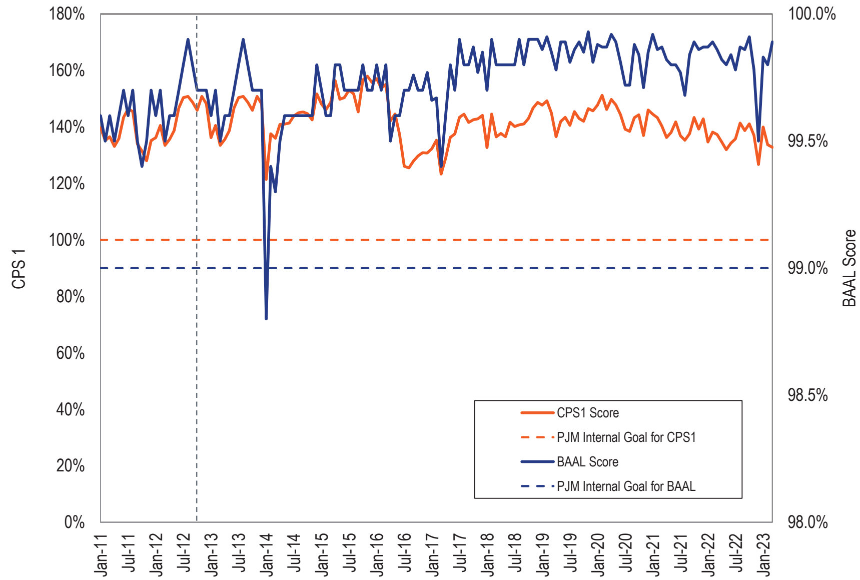
Table 10-50 Components of regulation cost: January 2022 through March 2023

Year	Month	Scheduled Regulation (MW)	Cost of Regulation Capability ($/MW)	Cost of Regulation Performance ($/MW)	Opportunity Cost ($/MW)	Total Cost ($/MW)
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	396,206.2	$112.30	$3.06	$20.33	$135.68
Yearly		4,550,354.2	$51.78	$4.00	$9.32	$65.10
2023	Jan	393,338.7	$17.27	$2.44	$5.24	$24.95
	Feb	362,742.5	$15.48	$2.89	$4.04	$22.40
	Mar	378,020.0	$17.77	$1.90	$5.48	$25.15
Total		1,134,101.3	$16.86	$2.40	$4.93	$24.20

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 March 2023 with the dashed vertical line marking the date (October 1, 2012) of the implementation of the Performance Based Regulation Market design.[103] The horizontal dashed lines represent PJM internal goals for CPS1 and BAAL performance.

Figure 10-26 Monthly CPS1 and BAAL performance: January 2011 through March 2023



103 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).[104] 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.[105] 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 is a regional approach that recognizes cost effective ways to provide black start across transmission zonal boundaries.[106] Under the current rules PJM has substantial flexibility in procuring black start resources and is responsible for black start resource selection.[107] But PJM's stated principles for system restoration are not fully incorporated into the rules in Schedule 6A. Costs should also be allocated on a regional basis.

The MMU recommends that black start planning and coordination be on a regional basis and not on a zonal basis. Similarly, the region as a whole benefits from black start service, regardless of the transmission zone in which it is located, and the costs of black start service should be shared equally across the region.

104 OATT Schedule 1 § 1.3BB.
105 *See* OATT Schedule 6A para. 18.
106 See Motion for Leave to Answer and Answer of PJM Interconnection, L.L.C to Comments, FERC Docket No. ER13-1911-000 (August 19, 2013) at 5 ("To be sure, restoration plans utilizing interconnecting Transmission Owners is not new and is currently included in all restoration plans today. Geographic or political boundaries play no role in the evaluation of the most reliable and efficient restoration strategies.").
107 *See* Docket No. ER13-1911-000.

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 June 2024. 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 June 2023.[108]

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.[109]

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.[110] 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.[111] 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.

108 RFPs issued can be found on the PJM website. See PJM. <http://www.pjm.com/markets-and-operations/ancillary-services.aspx>.
109 *See* OATT Schedule 6A para. 18.
110 There are no black start units currently using the ALR option.
111 OATT Schedule 6A (paras. 25, 26 and 27 outline how charges are to be applied).

In the first three months of 2023, total black start charges were $16.6 million, a decrease of $0.945 million (5.4 percent) from 2022. In the first three months of 2023, total revenue requirement charges were $16.48 million, a decrease of $0.929 million (5.33 percent) from 2022. In the first three months of 2023, total uplift charges were $0.109 million, a decrease of $0.016 million (12.97 percent) from 2022. Table 10-51 shows total charges for each year from 2010 through 2023.[112]

Table 10-51 Black start revenue requirement charges: January through March, 2010 through 2023

Jan-Mar	Revenue Requirement Charges	Uplift Charges	Total
2010	$2,673,689	$0	$2,673,689
2011	$2,793,709	$0	$2,793,709
2012	$3,864,301	$0	$3,864,301
2013	$5,412,855	$22,210,646	$27,623,501
2014	$5,104,104	$7,561,533	$12,665,637
2015	$10,276,712	$4,699,965	$14,976,676
2016	$16,677,315	$57,082	$16,734,396
2017	$17,731,836	$63,384	$17,795,220
2018	$16,840,283	$23,309	$16,863,592
2019	$15,938,101	$36,188	$15,974,289
2020	$15,944,660	$40,587	$15,985,247
2021	$16,483,246	$86,695	$16,569,941
2022	$17,408,156	$125,306	$17,533,462
2023	$16,479,646	$109,056	$16,588,702

Black start zonal charges in 2023 ranged from $0 in the OVEC and REC Zones to $4,821,152 in the AEP Zone. For each zone, Table 10-52 shows black start charges, zonal peak loads, and black start rates (calculated as charges per MW-day).[113] [114] Customers paid an average of $1.10 per MW-day for black start service in 2022.

112 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.
113 See "PJM Manual 27: Open Access Transmission Tariff Accounting,"§ 7.3 Black Start Service Charges, Rev. 97 (Feb. 1, 2023).
114 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.

Table 10-52 Black start zonal charges: January through March, 2022 and 2023[115]

	Jan-Mar 2022					Jan-Mar 2023				
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	$499,119	$0	$499,119	2,631	$2.11	$481,828	$0	$481,828	2,614	$2.05
AEP	$4,884,320	$0	$4,884,320	21,925	$2.48	$4,820,407	$745	$4,821,152	21,717	$2.47
APS	$1,611,837	$3,755	$1,615,592	8,865	$2.02	$1,614,258	$792	$1,615,050	9,154	$1.96
ATSI	$1,376,245	$0	$1,376,245	12,604	$1.21	$1,384,503	$8,976	$1,393,479	12,771	$1.21
BGE	$10,339	$0	$10,339	6,486	$0.02	$8,602	$0	$8,602	6,520	$0.01
COMED	$2,342,398	$3,773	$2,346,170	21,167	$1.23	$2,191,967	$35,761	$2,227,728	21,262	$1.16
DAY	$60,173	$24,487	$84,660	3,330	$0.28	$46,116	$28,039	$74,155	3,362	$0.25
DUKE	$98,924	$14,831	$113,755	5,306	$0.24	$61,956	$2,188	$64,144	5,166	$0.14
DUQ	$256,407	$0	$256,407	2,759	$1.03	$253,233	$0	$253,233	2,715	$1.04
DOM	$1,291,854	$67,128	$1,358,982	20,405	$0.74	$978,415	$19,368	$997,783	21,156	$0.52
DPL	$313,377	$1,609	$314,987	4,006	$0.87	$283,316	$0	$283,316	4,125	$0.76
EKPC	$85,168	$0	$85,168	2,851	$0.33	$66,151	$0	$66,151	2,994	$0.25
JCPLC	$149,542	$0	$149,542	6,169	$0.27	$127,626	$0	$127,626	6,123	$0.23
MEC	$140,901	$0	$140,901	3,072	$0.51	$87,866	$4,866	$92,732	3,021	$0.34
OVEC	$0	$0	$0	NA	NA	$0	$0	$0	NA	NA
PECO	$365,311	$1,651	$366,962	8,479	$0.48	$312,720	$1,399	$314,119	8,583	$0.41
PE	$1,089,932	$0	$1,089,932	2,900	$4.18	$1,062,363	$0	$1,062,363	2,830	$4.17
PEPCO	$83,724	$0	$83,724	5,829	$0.16	$43,281	$0	$43,281	5,834	$0.08
PPL	$1,213,849	$401	$1,214,250	7,517	$1.79	$1,214,124	$226	$1,214,350	7,489	$1.80
PSEG	$446,680	$0	$446,680	10,064	$0.49	$396,267	$0	$396,267	10,147	$0.43
REC	$0	$0	$0	NA	NA	$0	$0	$0	NA	NA
(Imp/Exp/Wheels)	$1,088,054	$7,672	$1,095,726	10,417	$1.17	$1,044,647	$6,695	$1,051,343	10,635	$1.10
Total	$17,408,156	$125,306	$17,533,462	166,781	$1.17	$16,479,646	$109,056	$16,588,702	168,218	$1.10

115 Peak load for each zone is used to calculate the black start rate per MW day.

Table 10-53 provides a revenue requirement estimate by zone for the 2022/2023, 2023/2024, and 2024/2025 Delivery Years.[116] 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.

Table 10-53 Black start zonal revenue requirement estimate: 2022/2023 through 2024/2025 Delivery Years[117]

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

116 The System Restoration Strategy Task Force requested that the MMU provide estimated black start revenue requirements.

117 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.

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.[118] 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.[119] 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.

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.[120] 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.

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

119 *Id.*

120 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.

The U.S. Internal Revenue Code changed significantly in December 2017.[121] The PJM CRF table did not change to reflect these changes.[122] [123] 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.[124] 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 start units, PJM's filing would have made the use of inaccurate values permanent. The MMU filed comments on April 28, 2021.[125] 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.[126] [127] 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.[128] 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."[129] The MMU requested rehearing over the Commission's conclusion that the MMU had requested "retroactive changes to the rates previously paid to generators."[130] [131] The request for rehearing was denied.[132] 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.[133]

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."[134] [135] 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.[136] Table 10-54 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 10-54 CRF over recovery if CRF not corrected for changes in tax laws[137]

	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

121 Tax Cuts and Jobs Act, Pub. L. No. 115-97, 131 Stat. 2096, Stat. 2105 (2017)
122 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.
123 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).
124 *See* Docket No. ER21-1635-000.
125 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>.
126 Answer and Motion for Leave to Answer of the independent Market Monitor for PJM, ER21-1635 (May 20, 2021).
127 Comments of the Independent Market Monitor for PJM, FERC Docket No. ER21-1635 (July 2, 2021).
128 176 FERC ¶ 61,080 at 42 and 44 (2021).
129 176 FERC ¶ 61,080 at 2 (2021).
130 Id. at 50.
131 Request for Rehearing of the Independent Market Monitor for PJM, FERC Docket No. ER21-1635 (September 9, 2021).
132 177 FERC ¶ 62,017 (2021).
133 177 FERC ¶ 61,202 (2021).
134 *PJM Interconnection, L.L.C., Response to Commission's Show Cause Order*, Docket No. EL21-91 (October 12, 2021).
135 August 10th Oder at 47.
136 Errata Filing of the Independent Market Monitor for PJM, Attachment B at 17, Docket No. EL21-91 (November 18, 2022).
137 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.

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.[138]

In an order on March 24, 2023, FERC "set for hearing and settlement judge procedures the determination of whether, as a result of changes from the TCJA, the existing CRF values result in a Capital Cost Recovery Rate for generating units that were selected to provide Black Start Service prior to June 6, 2021 that is unjust and unreasonable."[139]

NERC – CIP

No black start units have requested new or additional black start NERC – CIP Capital Costs.[140]

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.[141] In a 2023 MISO case, the Commission affirmed that RTOs and their customers are not required to compensate generation resources for such reactive capability.[142] Customers in PJM, nevertheless, pay $384.0 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.[143] Reactive capability charges are based on FERC approved filings for individual unit revenue requirements that are typically black box settlements.[144] 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.[145]

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.[146] [147]

In 2016, FERC began to reexamine its policies on reactive compensation.[148] On November 18, 2021, the FERC issued a notice of inquiry (NOI) concerning reactive power capability compensation.[149] The Market Monitor responded to the NOI.[150] 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.[151] Although this policy had been the practice in CAISO

138 Id. (Attachment B, Section H at 18).

139 182 FERC ¶ 61,194 at 32.

140 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."

141 OATT Attachment O.

142 *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).

143 See "PJM Manual 27: Open Access Transmission Tariff Accounting,"§ 3.2 Reactive Supply and Voltage Control Credits, Rev. 97 (Feb. 1, 2023).

144 OATT Schedule 2.

145 See OA Schedule 1 § 3.2.3B.

146 OATT Schedule 2.

147 See "PJM Manual 27: Open Access Transmission Tariff Accounting,"§ 3.3 Reactive Supply and Voltage Control Charges, Rev. 97 (Feb. 1, 2023).

148 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).

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

150 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).

151 *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).

and SPP, MISO shows that an RTO can remove compensation for reactive capability from its market rules.[152]

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 to meet certain reactive capability requirements as a condition to receive interconnection service and no separate compensation is required.[153] 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.

152 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)

153 Attachment O.

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 *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.[154]

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.

154 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 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 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 10-58)

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.[155] 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.[156] 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

155 *See* OATT Attachment DD § 5.10(a)(v)(A).
156 OATT Attachment DD § 6.8(d).

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.[157]

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."[158] 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."[159] The Monitored and Reportable Transmission Facilities are included in the Transmission Facilities List. The Transmission Facilities List is located on the PJM website.

157 See, e.g., FERC Docket Nos. ER21-2091, ER21-936, ER21-737, ER20-1863 & ER20-1851.

PJM's criteria for defining Monitored Transmission Facilities and the criteria for defining Reportable Transmission Facilities determine which power lines 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.[160]

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."[161] The Judge determined that none of the facilities in the four cases at hearing "satisfy the second criterion."[162] 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.[163] The initial decision provides a reasonable resolution to the eligibility issue. The principal advantage of

158 See PJM Manual 03: Transmission Operations, Rev. 63 (Nov. 16, 2022).
159 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)>.
160 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.
161 See 180 FERC ¶ 63,009 at P 5 (2022).
162 *Id.*
163 *Id.*

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.[164] 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.[165] 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.[166] 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.[167]

Table 10-55 identifies fleet rates currently effective in PJM.

Table 10-55 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

164 See 80 FERC ¶ 63,006 (1997), *aff'd*, 88 FERC ¶ 61,141 (1999).
165 See, e.g., OATT Schedule 2; 114 FERC ¶ 61,318 (2006).
166 See 149 FERC ¶ 61,132 (2014); 151 FERC ¶ 61,224 (2015); OATT Schedule 2.
167 *Id.*

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.[168] But PJM rules require fleet owners only to submit informational filings when a reactive unit is transferred or deactivated.[169] The current rules do not require a rate filing, which would place the burden of proof on the company and allow for cost review.[170]

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 unit in the fleet.[171] 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.[172] 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.[173]

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 the first three months of 2023, total reactive charges were $96.3 million, an increase of $0.5 million (0.5 percent) from 2022. In the first three months of 2023, total reactive capability charges were $96.3 million, an increase of $0.7 million (0.8 percent) from 2022. In the first three months of 2023, total reactive service charges were $0.0 million, a decrease of $0.2 million (100.0 percent) from 2022.

168 151 FERC ¶ 61,224 at P 29 (2015).
169 OATT Schedule 2.
170 *Id.*
171 *See* Letter Opposing Settlement, Docket No ER06-554 et al. (June 14, 2017).
172 *Id.*
173 162 FERC ¶ 61,029 (2018).

Table 10-56 shows reactive service charges for the first three months of each year from 2010 through 2023.

Table 10-56 Reactive service charges and reactive capability charges: January through March, 2010 through 2023

Jan-Mar	Reactive Service Charges	Reactive Capability Charges	Total
2010	$1,462,979	$60,140,250	$61,603,229
2011	$7,901,985	$61,525,380	$69,427,366
2012	$22,774,605	$68,171,375	$90,945,980
2013	$55,579,356	$68,330,702	$123,910,058
2014	$7,589,161	$70,631,766	$78,220,927
2015	$6,330,318	$69,482,495	$75,812,813
2016	$250,496	$72,742,919	$72,993,415
2017	$5,872,960	$75,383,924	$81,256,884
2018	$6,054,364	$74,884,662	$80,939,026
2019	$124,821	$80,560,451	$80,685,272
2020	$45,745	$85,367,740	$85,413,485
2021	$705,618	$89,263,898	$89,969,516
2022	$231,202	$95,529,569	$95,760,770
2023	$0	$96,254,033	$96,254,033

Table 10-57 shows zonal reactive service charges for 2022 and 2023, 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.

Table 10-57 Reactive service charges and reactive capability charges by zone: January through March, 2022 and 2023

	Jan-Mar 2022			Jan-Mar 2023		
Zone	Reactive Service Charges	Reactive Capability Charges	Total Charges	Reactive Service Charges	Reactive Capability Charges	Total Charges
ACEC	$0	$1,057,110	$1,057,110	$0	$729,962	$729,962
AEP	$0	$12,248,882	$12,248,882	$0	$13,367,105	$13,367,105
APS	$0	$5,430,477	$5,430,477	$0	$5,619,367	$5,619,367
ATSI	$0	$7,693,246	$7,693,246	$0	$7,155,544	$7,155,544
BGE	$0	$1,635,182	$1,635,182	$0	$1,633,896	$1,633,896
COMED	$0	$10,345,046	$10,345,046	$0	$11,481,877	$11,481,877
DAY	$0	$693,467	$693,467	$0	$692,922	$692,922
DUKE	$0	$2,629,533	$2,629,533	$0	$1,969,123	$1,969,123
DOM	$225,700	$12,300,517	$12,526,217	$0	$13,274,101	$13,274,101
DPL	$5,502	$2,553,565	$2,559,067	$0	$2,375,054	$2,375,054
DUQ	$0	$140,537	$140,537	$0	$20,408	$20,408
EKPC	$0	$536,908	$536,908	$0	$536,485	$536,485
JCPLC	$0	$1,856,165	$1,856,165	$0	$2,047,068	$2,047,068
MEC	$0	$1,489,735	$1,489,735	$0	$1,488,564	$1,488,564
OVEC	$0	$0	$0	$0	$0	$0
PECO	$0	$4,958,443	$4,958,443	$0	$5,242,037	$5,242,037
PE	$0	$4,306,240	$4,306,240	$0	$4,302,853	$4,302,853
PEPCO	$0	$2,630,930	$2,630,930	$0	$2,182,354	$2,182,354
PPL	$0	$9,056,346	$9,056,346	$0	$9,021,376	$9,021,376
PSEG	$0	$7,713,084	$7,713,084	$0	$6,738,988	$6,738,988
REC	$0	$0	$0	$0	$0	$0
(Imp/Exp/Wheels)	$0	$6,254,156	$6,254,156	$0	$6,374,949	$6,374,949
Total	$231,202	$95,529,569	$95,760,770	$0	$96,254,033	$96,254,033

Table 10-58 shows the units which received reactive service credits in the first three months of 2023. In the first three months of 2023 there were no reactive service credits.

Table 10-58 Reactive service credits by plant (Total dollars): January through March, 2023

	Jan-Mar 2023	
Zone	Plant	Reactive Service Credits
	None	$0
Total		$0

Table 10-59 shows the settled reactive capability revenue requirements by technology effective on March 1, 2023.[174] 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.

Table 10-59 Total settled reactive revenue requirements by unit type and fuel type: March 1, 2023

Unit Type	Fuel Type	Total Revenue Requirement per Year	MW	Number of Resources	Requirement per MW-year
CC	Gas	$123,835,318.40	49,428.4	155	$2,505.35
CT	Gas	$45,501,159.43	28,273.7	247	$1,609.31
CT	Oil	$4,618,995.17	3,239.4	111	$1,425.88
Diesel	Gas	$1,380,092.00	105.8	5	$13,044.35
Diesel	Oil	$1,029,458.66	168.1	36	$6,124.08
Diesel	Other - Gas	$914,468.84	114.6	11	$7,979.66
FC	Gas	$45,000.00	2.6	1	$17,307.69
Hydro	Water	$17,816,173.03	6,890.4	52	$2,585.65
Nuclear	Nuclear	$57,524,969.57	32,607.3	31	$1,764.17
Solar	Solar	$3,409,893.89	424.1	15	$8,040.31
Steam	Coal	$53,331,122.69	41,201.1	67	$1,294.41
Steam	Gas	$5,202,743.36	5,603.6	18	$928.46
Steam	Oil	$3,489,074.18	2,852.3	9	$1,223.25
Steam	Other - Solid	$340,000.00	34.0	2	$10,000.00
Steam	Wood	$207,796.25	153.0	3	$1,358.15
Wind	Wind	$18,664,267.97	4,820.9	37	$3,871.53
Total		$337,310,533.44	175,919.3	800	$1,917.42

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.[175] 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 evaluates generators' primary frequency capabilities using two to three frequency events per month, with events being chosen on the criteria that the frequency stays outside ±0.040 Hz deadband for at least one minute, and the minimum/maximum frequency reaches ±0.053 Hz.[176] The performance of each unit is evaluated quarterly.

PJM filed revisions in compliance with Order No. 842 that substantively incorporated the pro forma agreements into its market rules.[177]

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

174 The total amount in the final row of Table 10-32 is the amount that would be paid if the total rate effective on March 1, 2023 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.
175 157 FERC ¶ 61,122 (2016).
176 See PJM Manual 12 (Balancing Operations) § 3.6.2.
177 See 164 FERC ¶ 61,224 (2018).

is to arrest and stabilize the system until other measures (secondary and tertiary frequency response) become active.

- **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.

Congestion and Marginal Losses

When there are binding transmission constraints and locational price differences, load pays more for energy than generation is paid to produce that energy.[1] The difference is congestion.[2] As a result, congestion belongs to load and should be returned to load. Congestion is not the difference in CLMP between nodes. Congestion is not the billing line item labeled congestion.[3]

The locational marginal price (LMP) is the incremental price of energy at a bus. The LMP at a bus can be divided into three components: the system marginal price (SMP) or energy component, the congestion component (CLMP), and the marginal loss component (MLMP). SMP, MLMP and CLMP are the simultaneous products of the least cost, security constrained dispatch of system resources to meet system load and the use of a load-weighted reference bus. The relative values of SMP and CLMP are arbitrary and depend on the reference bus.

SMP is defined as the incremental price of energy for the system, given the current dispatch, at the load-weighted reference bus, or LMP net of losses and congestion. SMP is the LMP at the load-weighted reference bus. The load-weighted reference bus is not a fixed location but varies with the distribution of load at system load buses. For SMP, energy means the component of LMP not associated with a binding transmission constraint. All other locational prices that result from the least cost, security constrained market solution are higher or lower than this reference point price (SMP) as a result of binding constraints. The reference bus is a point of reference. For a given market solution, changing the reference bus does not change the LMP for any node on the system, but changes only the elements of the nodal prices that are positive or negative due to the binding constraints in that solution. CLMP is defined as the incremental price of meeting load at each bus when a transmission constraint is binding, based on the shadow price associated with the relief of a binding transmission constraint in the security constrained optimization. (There can be multiple binding transmission constraints.) CLMPs are positive or negative depending on location relative to binding constraints and relative to the load-weighted reference bus. In an unconstrained system CLMPs will be zero. This means that CLMP at a bus is not congestion. The difference between CLMPs at buses is not congestion, it is just the absolute LMP difference between the two buses caused by transmission constraints. CLMP is the portion of the LMP at a bus that indicates whether the LMP at that bus is higher or lower than the marginal price of energy SMP at the selected reference bus due to binding transmission constraints. The relative values of SMP and CLMP are arbitrary and depend on the reference bus.

MLMP is defined as the incremental price of losses at a bus, based on marginal loss factors in the security constrained optimization. Losses refer to energy lost to physical resistance in the transmission network as power is moved from generation to load.

Total losses refer to total system wide transmission losses as a result of moving power from injections to withdrawals on the system. Marginal losses are the incremental change in system losses caused by changes in load and generation.

Congestion is neither good nor bad, but is a direct measure of the extent to which there are multiple marginal generating units with different offers dispatched to serve load as a result of transmission constraints. Congestion occurs when available, least-cost energy cannot be delivered to all load because transmission facilities are not adequate to deliver that energy to one or more areas, and higher cost units in the constrained area(s) must be dispatched to meet the load.[4] The result is that the price of energy in the constrained area(s) is higher than in the unconstrained area. Load in the constrained area pays the single higher price for all the energy used, including energy from low cost and energy from high cost generation, while generators are each paid the price at their individual bus. Congestion is the difference between what load pays based on the single higher price at load buses and what generators receive based on the lower prices at the individual generator buses due to binding transmission constraints.

1 Load is generically referred to as withdrawals and generation is generically referred to as injections, unless specified otherwise.
2 The difference in losses is not part of congestion.
3 PJM billing examples can be found in *2022 State of the Market Report for PJM*, Appendix F: Congestion and Marginal Losses.
4 This is referred to as dispatching units out of economic merit order. Economic merit order is the order of all generator offers from lowest to highest cost. Congestion occurs when loadings on transmission facilities mean the next unit in merit order cannot be used and a higher cost unit must be used in its place. Dispatch within the constrained area follows merit order for the units available to relieve the constraint.

The energy, marginal losses and congestion metrics must be interpreted carefully.

In PJM accounting, the term total congestion refers to net implicit CLMP charges plus net explicit CLMP charges plus net inadvertent CLMP charges. The net implicit CLMP charges are the implicit withdrawal CLMP charges less implicit injection CLMP credits.

As with congestion, total system energy costs are more precisely termed net system energy costs and total marginal loss costs are more precisely termed net marginal loss costs. Ignoring interchange, total generation MWh must be greater than total load MWh in any hour in order to provide for losses. Since the hourly integrated energy component of LMP is the same for every bus within every hour, the net energy bill is negative (ignoring net interchange), with more generation credits than load payments in every hour.[5]

While PJM accounting focuses on CLMPs, the individual CLMP values at any bus are irrelevant to the calculation of congestion, as CLMPs are just an artificial deconstruction of LMP based on a selected reference bus. Holding aside the marginal loss component of LMP, differences in the LMPs are caused by binding constraints in the least cost security constrained dispatch market solution and total congestion is the net surplus revenue that remains after all sources and sinks are credited or charged their LMPs. Changing the components of LMP by electing a different reference bus does not change the LMPs or the difference between LMPs for a given market solution, it merely changes the components of the LMP.

Local congestion is the congestion paid by load at a specific bus or set of buses and is calculated on a constraint specific basis. For a given market solution, a change in the elected reference bus does not change the LMP at any bus and does not change total congestion paid by load and does not change the local congestion paid by load at a specific location. Holding aside the marginal loss component of LMP, local congestion is the sum of the total LMP charges to load at the defined set of buses minus the sum of the total LMP credits received by all generation that supplied that load, given the set of all binding transmission constraints, regardless of location. Local congestion reflects the underlying characteristics of the complete power system as it affects the defined area, including the nature and capability of transmission facilities, the offers and geographic distribution of generation facilities, the level and geographic distribution of incremental bids and offers and the geographic and temporal distribution of load. Local congestion fully reflects the least cost security constrained system solution and the LMPs that result from that solution.

PJM implemented fast start pricing in both day-ahead and real-time markets starting September 1, 2021. PJM's fast start pricing logic results in pricing run locational marginal prices (PLMP). PLMP is the price that load pays and generators receive in the PJM energy market.

While PLMP is the official settlement price, PJM continues to calculate LMP based on the logic that PJM uses to actually dispatch system resources and used prior to the introduction of fast start to consistently define dispatch and prices. The LMPs from the dispatch run are dispatch run locational marginal prices (DLMP). While the settlement prices are PLMP, settlement MW are based on the dispatch run in the day-ahead market and are metered output in the real-time market.

PJM uses artificial constraints in the day-ahead and real-time markets to force specific resources (generation or demand response) to be marginal in order to have those resources set price. The uniform source dfax and uniform sink dfax of the artificial constraint can be modified, along with the line limits, by PJM to meet market outcome goals and are a source of often significant modeling differences between the day ahead and real time market. These modeling differences result in inefficient market outcomes and false arbitrage opportunities for virtual transactions. These artificial constraints have been used to hide uplift costs by making them negative congestion charges. The use of artificial constraints is an inappropriate use of PJM discretion as the market operator, putting PJM in the position of a market actor, arbitrarily changing market results, market prices, generation revenues, congestion costs and load charges.

5 The total congestion and marginal losses for 2023 were calculated as of April 10, 2023, and are subject to change, based on continued PJM billing updates.

Overview

Congestion Cost

- **Total Congestion.** Total congestion costs decreased by $334.8 million or 65.6 percent, from $510.3 million in the first three months of 2022 to $175.5 million in the first three months of 2023.
- **Day-Ahead Congestion.** Day-ahead congestion costs decreased by $475.2 million or 67.7 percent, from $701.4 million in the first three months of 2022 to $226.2 million in the first three months of 2023.
- **Balancing Congestion.** Negative balancing congestion costs decreased by $140.4 million, from -$191.2 million in the first three months of 2022 to -$50.8 million in the first three months of 2023. Negative balancing explicit charges decreased by $18.4 million, from -$65.1 million in the first three months of 2022 to -$46.7 million in the first three months of 2023.
- **Real-Time Congestion.** Real-time congestion costs decreased by $765.1 million, from $936.3 million in the first three months of 2022 to $171.1 million in the first three months of 2023.
- **Monthly Congestion.** Monthly total congestion costs in the first three months of 2023 ranged from $26.8 million in March to $86.4 million in February.
- **Geographic Differences in CLMP.** Differences in CLMP between southern and eastern control zones in PJM were primarily a result of binding constraints on the Nottingham Series Reactor, the Beaumeade Circuit Breaker, the AP South Interface, the Gardners - Texas Eastern Line and the Bedington - Black Oak Interface.
- **Congestion Frequency.** Congestion frequency continued to be significantly higher in the day-ahead energy market than in the real-time energy market in the first three months of 2023. The number of congestion event hours in the day-ahead energy market was about four and half times the number of congestion event hours in the real-time energy market.

  Day-ahead congestion frequency decreased by 11.8 percent from 21,091 congestion event hours in the first three months of 2022 to 18,602 congestion event hours in the first three months of 2023.

  Real-time congestion frequency decreased by 52.1 percent from 8,431 congestion event hours in the first three months of 2022 to 4,040 congestion event hours in the first three months of 2023.
- **Congested Facilities.** Day-ahead, congestion event hours decreased on all types of facilities except transformers.

  The Nottingham Series Reactor was the largest contributor to congestion costs in the first three months of 2023. With $44.1 million in total congestion costs, it accounted for 25.2 percent of the total PJM congestion costs in the first three months of 2023.
- **CT Price Setting Logic and Closed Loop Interface Related Congestion.** PJM's use of CT pricing logic officially ended with the implementation of fast start pricing on September 1, 2021. While CT pricing logic was officially discontinued by PJM on September 1, 2021, PJM continues to use a related logic to force inflexible units and demand response to be on the margin in both real time and day ahead. None of the PJM defined closed loop interfaces were binding in the first three months of 2023 or 2022.
- **Zonal Congestion.** AEP had the highest zonal congestion costs among all control zones in the first three months of 2023. AEP had $27.8 million in zonal congestion costs, comprised of $35.3 million in day-ahead congestion costs and -$7.5 million in balancing congestion costs.

Marginal Loss Cost

- **Total Marginal Loss Costs.** Total marginal loss costs decreased by $191.9 million or 48.8 percent, from $393.1 million in the first three months of 2022 to $201.2 million in the first three months of 2023. The loss MWh in PJM decreased by 731.1 GWh or 15.7 percent, from 4,648.0 GWh in the first three months of 2022 to 3,916.9 GWh in the first three months of 2023. The loss component of real-time LMP in the first three months of 2023 was $0.02, compared to $0.04 in the first three months of 2022.

- **Day-Ahead Marginal Loss Costs.** Day-ahead marginal loss costs decreased by $202.6 million or 47.6 percent, from $425.4 million in the first three months of 2022 to $222.8 million in the first three months of 2023.
- **Balancing Marginal Loss Costs.** Negative balancing marginal loss costs decreased by $10.7 million or 33.1 percent, from -$32.3 million in the first three months of 2022 to -$21.6 million in the first three months of 2023.
- **Total Marginal Loss Surplus.** The total marginal loss surplus decreased by $62.8 million or 48.9 percent, from $128.5 million in the first three months of 2022, to $65.7 million in the first three months of 2023.
- **Monthly Total Marginal Loss Costs.** Monthly total marginal loss costs in the first three months of 2023 ranged from $56.1 million in March to $78.8 million in January.

System Energy Cost

- **Total System Energy Costs.** Total system energy costs increased by $125.3 million or 48.0 percent, from -$260.8 million in the first three months of 2022 to -$135.6 million in the first three months of 2023.
- **Day-Ahead System Energy Costs.** Day-ahead system energy costs increased by $97.4 million or 34.9 percent, from -$279.1 million in the first three months of 2022 to -$181.7 million in the first three months of 2023.
- **Balancing System Energy Costs.** Balancing system energy costs increased by $28.6 million or 153.2 percent, from $18.7 million in the first three months of 2022 to $47.2 million in the first three months of 2023.
- **Monthly Total System Energy Costs.** Monthly total system energy costs in the first three months of 2023 ranged from -$59.2 million in January to -$37.5 million in March.

Conclusion

Congestion is defined as the total payments by load in excess of the total payments to generation, excluding marginal losses. The level and distribution of congestion reflects the underlying characteristics of the power system, including the nature and defined capability of transmission facilities, the offers and geographic distribution of generation facilities, the level and geographic distribution of incremental bids and offers and the geographic and temporal distribution of load.

Total congestion costs decreased by $334.8 million or 65.6 percent, from $510.3 million in the first three months of 2022 to $175.5 million in the first three months of 2023 due to cold weather in January of 2022 and mild weather in the first three months of 2023.

Monthly total congestion costs ranged from $26.8 million in March to $86.4 million in February in the first three months of 2023.

The current ARR/FTR design does not ensure that load receives the rights to all congestion revenues. The congestion offset provided by ARRs and self scheduled FTRs in the first ten months of the 2022/2023 planning period was 75.6 percent. The cumulative offset of congestion by ARRs for the 2011/2012 planning period through the first ten months of the 2022/2023 planning period, using the rules effective for each planning period, was 69.0 percent. Load has received $3.8 billion less than load should have received from the 2011/2012 planning period through the first ten months of the 2022/2023 planning period.

Issues

Artificial Constraints, Closed Loop Interfaces and CT Pricing Logic

PJM has used, and in some cases, continues to use, artificial constraints in the day ahead and real time markets to force specific resources (generation or demand response) to be marginal in order to have those resources set price. Some of these artificial constraints, such as CT pricing logic and closed loop interfaces, result in negative congestion charges that are an artifact of the artificial nature of the constraints that cause generation to be paid more than load pays for energy affected by the constraint. PJM also makes use of artificial constraints that function like closed loop interfaces but which result in positive congestion. These constraints are similar to a closed loop interface in that they enforce artificially uniform price effects, but unlike closed loop interfaces that only affect prices on the constrained side, these artificial constraints enforce artificially uniform price spreads between the two sides of the constraint. These artificial constraints take the form of interfaces or enforced contingencies (modifications) on existing constraints. The uniform source dfax and uniform sink dfax of the artificial constraint can be modified, along with the transmission line limits, by PJM to meet market outcome goals and are a source of often significant modeling differences between the day-ahead and real-time market. These modeling differences result in inefficient market outcomes and false arbitrage opportunities for virtual transactions. This is an inappropriate use of these tools as it puts PJM in the position of a market actor, arbitrarily changing market results, market prices, generation revenues, congestion costs and load charges. One of the side effects of these changes in parameters, besides causing modeling differences between the day ahead and real time market, is that the apparent location of the interface or parent constraint can move intra day relative to source and sink points.

While CT pricing logic was officially discontinued by PJM with the implementation of fast start pricing on September 1, 2021, PJM continues to use the same basic logic to force inflexible units to be on the margin in both real-time and day-ahead. PJM used CT pricing logic to force otherwise uneconomic resources to be marginal and set price in the day-ahead or real-time market solution. PJM used CT pricing logic to create an artificial constraint with a variable flow limit, paired with an artificial override of the inflexible resource's economic minimum, to make the resource marginal in PJM's LMP security constrained pricing logic. The purpose of forcing inflexible units to be marginal is to reduce the uplift associated with the dispatch of inflexible resources.

Through the assumption of artificial flexibility of the affected unit and artificially creating a constraint for which the otherwise inflexible resource can be marginal, PJM's use of CT pricing logic forced the affected resource bus LMP to match the marginal offer of the resource. PJM adjusts the constraint limit based on the output of the resource. Sometimes the constraint limit does not match the flows on the constraint, and the constraint violates instead of binding, resulting in prices set by the transmission constraint penalty factor.

In the case of a closed loop interface, all buses within the interface were modeled with a distribution factor (dfax) of 1.0 to the constraint and therefore with the same constraint related congestion component of price at the marginal resource's bus. In the CT pricing logic case, the constraint affected the CLMP of constrained side buses in proportion to their dfax to that constraint.[6] One objective of making inflexible resources marginal was to artificially minimize the uplift costs associated with the inflexible resources that PJM commits for system security reasons.

The use of artificial constraints was and is a source of modeling differences between the day-ahead and real-time markets. When artificial constraints are not included in the day-ahead market in exactly the same way as in the real-time market, including specific constraints and limits, the differences between the day-ahead and real-time market model result in positive or negative balancing congestion.

Failure to model the same constraints in the day-ahead and real-time markets results in pricing and congestion settlement differences between the day-ahead and real-time market. Any modeling differences create false arbitrage opportunities for virtual bids and contribute to negative balancing congestion.

Use of artificial constraints, closed loop interfaces and CT price setting logic requires manipulation of the economic dispatch model. Closed loop interfaces and CT price setting logic, like fast start pricing logic that replaced it, force higher cost inflexible units to be marginal.

Like closed loop interfaces and CT pricing logic, some of the artificially enforced constraint results in negative congestion. As a result, more power is produced in the artificial closed loop or constrained area than would result without the artificial constraint. This means that there are more generation credits than load charges in the constrained area. The constrained area exports power, the lower cost generators outside the constrained area are backed down and prices are lower outside the constrained area as a result. All of the generation within the artificially constrained area is paid the higher CLMP, but only a smaller amount of load (in some cases no load) in the constrained area pays

6 The constrained side means the higher priced side with a positive CLMP created by the constraint.

this higher CLMP. As a result, load pays less than generation receives in the artificially constrained area. This difference is negative congestion. In the day-ahead market this reduces the total congestion dollars that are available to FTR holders. In the balancing market these costs are allocated directly to load as negative balancing charges.

Locational Marginal Price (LMP)

Components

PJM uses a distributed load reference bus. With a distributed load reference bus, the energy component of LMP is a load-weighted system price. Some price effects of binding constraint may be included in the load-weighted reference bus price.

LMP at a bus reflects the incremental price of energy at that bus. LMP at any bus can be disaggregated into three components: the system marginal price (SMP), marginal loss component (MLMP), and congestion component (CLMP).

SMP, MLMP and CLMP are a product of the least cost, security constrained dispatch of system resources to meet system load. SMP is the incremental cost of system energy, given the current dispatch and given the choice of reference bus. SMP is LMP net of losses and congestion. Losses refer to energy lost to physical resistance in the transmission and distribution network as power is moved from generation to load. Marginal losses are the incremental change in system power losses caused by changes in the system load and generation patterns.[7] The first derivative of total losses with respect to the power flow is marginal losses. Congestion cost reflects the incremental cost of relieving transmission constraints while maintaining system power balance. Congestion occurs when available, least-cost energy cannot be delivered to all loads because transmission facilities are not adequate to deliver that energy. When the least-cost available energy cannot be delivered to load in a transmission constrained area, higher cost units in the constrained area must be dispatched to meet that load.[8] The result is that the price of energy in the constrained area is higher than in the unconstrained area because of the combination of transmission limitations and the cost of local generation. Load in the constrained area pays the higher price for all energy including energy from low cost generation and energy from high cost generation. Congestion is the difference between the total cost of energy paid by load in the transmission constrained area and the total revenue received by generation to meet the load in the transmission constrained area, net of losses. Congestion equals the sum of day-ahead and balancing congestion.

Table 11-1 shows the PJM real-time load-weighted average LMP components for January through March, 2008 through 2023.[9]

The real-time load-weighted average LMP decreased by $23.85 or 44.1 percent from $54.13 in the first three months of 2022 to $30.28 in the first three months of 2023. The real-time load-weighted average congestion component was $0.02 in the first three months of 2023, compared to $0.06 in the first three months of 2022. The real-time load-weighted, average loss component in the first three months of 2023 was $0.02, compared to $0.04 in the first three months of 2022. The real-time load-weighted average system energy component decreased by $23.80 or 44.0 percent from $54.03 in the first three months of 2022 to $30.23 in the first three months of 2023. Using a load-weighted reference bus, the real-time load-weighted average congestion component of LMP should be zero. PJM's load-weighted reference bus congestion component is zero at the time that LMPs are set based on state estimator data. Metering updates during the settlement process change the load weights after the fact, but the reference bus price (SMP) is not updated with these changes over time. As a result, the average congestion and loss components used in real-time settlement are not zero, although these components are not fully accurate.

7 For additional information, see the *MMU Technical Reference for PJM Markets*, at "Marginal Losses," <http://www.monitoringanalytics.com/reports/Technical_References/references.shtml>.

8 This is referred to as dispatching units out of economic merit order. Economic merit order is the order of all generator offers from lowest to highest cost. Congestion occurs when loadings on transmission facilities mean the next unit in merit order cannot be used and a higher cost unit must be used in its place.

9 The PJM real-time, load-weighted price is weighted by accounting load, which differs from the state-estimated load used in determination of the energy component (SMP). In the real-time energy market, the distributed load reference bus is weighted by state-estimated load in real time. When the LMP is calculated in real time, the energy component equals the system load-weighted price. But real-time bus-specific loads are adjusted, after the fact, based on updated load information from meters. This meter adjusted load is accounting load that is used in settlements and is used to calculate reported PJM load-weighted prices. This after the fact adjustment means that the real-time energy market energy component of LMP (SMP) and the PJM real-time load-weighted LMP are not equal. The difference between the real-time energy component of LMP and the PJM wide real-time load-weighted average LMP is a result of the difference between state-estimated and metered loads used to weight the load-weighted reference bus and the load-weighted LMP. Without these adjustments, the congestion component of system average LMP would be zero.

Table 11-1 Real-time load-weighted average LMP components (Dollars per MWh): January through March, 2008 through 2023[10]

(Jan - Mar)	Real-Time LMP	Energy Component	Congestion Component	Loss Component
2008	$69.35	$69.27	$0.04	$0.04
2009	$49.60	$49.51	$0.05	$0.04
2010	$45.92	$45.81	$0.06	$0.05
2011	$46.35	$46.30	$0.03	$0.03
2012	$31.21	$31.18	$0.02	$0.00
2013	$37.41	$37.37	$0.02	$0.02
2014	$92.98	$93.08	($0.13)	$0.03
2015	$50.91	$50.89	($0.00)	$0.03
2016	$26.80	$26.75	$0.03	$0.01
2017	$30.28	$30.25	$0.02	$0.02
2018	$49.45	$49.39	$0.03	$0.03
2019	$30.16	$30.12	$0.02	$0.02
2020	$19.85	$19.83	$0.01	$0.01
2021	$30.84	$30.79	$0.03	$0.02
2022	$54.13	$54.03	$0.06	$0.04
2023	$30.28	$30.23	$0.02	$0.02

Table 11-2 shows the PJM day-ahead load-weighted average LMP components for January through March, 2008 through 2023. The day-ahead load-weighted average LMP decreased by $22.07, or 40.7 percent, from $54.23 in the first three months of 2022 to $32.16 in the first three months of 2023. The day-ahead load-weighted average congestion component decreased by $0.64 from $0.63 in the first three months of 2022 to -$0.01 in the first three months of 2023. The day-ahead load-weighted average loss component was $0.05 in the first three months of 2023, compared to $0.34 in the first three months of 2022. The day-ahead load-weighted average energy component decreased by $21.14, or 39.7 percent, from $53.26 in the first three months of 2022 to $32.12 in the first three months of 2023. Using a load-weighted reference bus, the day-ahead load-weighted average congestion component of LMP should be zero. PJM's load-weighted reference bus congestion component is zero based on day-ahead firm load weights. Total billing however, includes price sensitive demand and virtual load congestion related charges, which makes the total load weights in accounting different than the load weights used to determine the SMP at the load-weighted reference bus. The resulting load-weighted average price from settlement for congestion and marginal losses components of price in day ahead is therefore not zero, although this component is not fully accurate.

10 Calculated values shown in Section 11, "Congestion and Marginal Losses," are based on unrounded, underlying data and may differ from calculations based on the rounded values in the tables.

Table 11-2 Day-ahead load-weighted average LMP components (Dollars per MWh): January through March, 2008 through 2023

(Jan - Mar)	Day-Ahead LMP	Energy Component	Congestion Component	Loss Component
2008	$68.00	$68.14	$0.05	($0.20)
2009	$49.44	$49.75	($0.18)	($0.13)
2010	$47.77	$47.74	$0.01	$0.02
2011	$47.14	$47.36	($0.11)	($0.11)
2012	$31.51	$31.45	$0.08	($0.03)
2013	$37.26	$37.19	$0.07	$0.01
2014	$94.96	$94.52	$0.43	$0.00
2015	$52.02	$51.55	$0.48	($0.02)
2016	$27.94	$27.80	$0.15	($0.00)
2017	$30.40	$30.39	$0.03	($0.02)
2018	$47.55	$47.36	$0.20	($0.01)
2019	$30.76	$30.66	$0.11	($0.01)
2020	$20.12	$20.14	($0.01)	($0.01)
2021	$31.58	$31.34	$0.19	$0.05
2022	$54.23	$53.26	$0.63	$0.34
2023	$32.16	$32.12	($0.01)	$0.05

Table 11-3 shows the PJM real-time load-weighted average LMP by constrained and unconstrained hours.

Table 11-3 Real-time load-weighted average LMP by constrained and unconstrained hours (Dollars per MWh): January 2022 through March 2023

	2022		2023	
	Constrained Hours	Unconstrained Hours	Constrained Hours	Unconstrained Hours
Jan	$69.75	$38.74	$37.40	$31.27
Feb	$47.17	$38.47	$26.93	$22.03
Mar	$43.43	$47.62	$28.42	$28.44
Apr	$63.91	$0.00		
May	$84.99	$58.69		
Jun	$105.87	$54.44		
Jul	$98.97	$59.33		
Aug	$125.07	$72.12		
Sep	$80.41	$63.94		
Oct	$56.22	$42.28		
Nov	$53.58	$48.87		
Dec	$155.97	$49.83		
Avg	$82.56	$57.72	$30.78	$27.88

Zonal Components

The real-time components of LMP for each control zone are presented in Table 11-4 for January through March, 2022 and 2023. In the first three months of 2023, DOM had the highest real-time congestion component of all control zones, $3.22, and PECO had the lowest real-time congestion component, -$3.87.

Table 11-4 Zonal real-time load-weighted average LMP components (Dollars per MWh): January through March, 2022 and 2023

	2022 (Jan - Mar)				2023 (Jan - Mar)			
	Real-Time LMP	Energy Component	Congestion Component	Loss Component	Real-Time LMP	Energy Component	Congestion Component	Loss Component
ACEC	$58.69	$54.50	$2.12	$2.07	$27.46	$30.46	($3.15)	$0.15
AEP	$48.84	$53.74	($3.73)	($1.16)	$30.58	$30.22	$0.55	($0.19)
APS	$53.11	$54.33	($1.27)	$0.05	$31.37	$30.30	$0.98	$0.09
ATSI	$47.33	$53.06	($5.14)	($0.59)	$30.29	$30.02	$0.25	$0.02
BGE	$64.33	$55.22	$6.57	$2.54	$33.79	$30.47	$2.20	$1.12
COMED	$38.89	$52.67	($10.37)	($3.41)	$26.82	$29.93	($1.84)	($1.28)
DAY	$49.56	$53.36	($4.12)	$0.32	$31.83	$30.17	$0.80	$0.86
DOM	$64.54	$55.10	$8.28	$1.16	$34.21	$30.38	$3.22	$0.61
DPL	$69.86	$55.47	$10.98	$3.41	$30.07	$30.55	($1.16)	$0.68
DUKE	$48.12	$53.57	($3.78)	($1.67)	$31.12	$30.22	$0.89	$0.01
DUQ	$45.66	$53.49	($6.24)	($1.59)	$29.95	$30.06	$0.27	($0.38)
EKPC	$49.80	$55.00	($3.57)	($1.63)	$31.30	$30.61	$0.78	($0.10)
JCPLC	$60.51	$54.29	$3.88	$2.34	$27.65	$30.38	($3.08)	$0.35
MEC	$60.83	$54.10	$5.40	$1.33	$29.77	$30.25	($0.45)	($0.03)
OVEC	$46.22	$52.59	($4.05)	($2.32)	$29.99	$29.80	$0.84	($0.64)
PE	$54.05	$53.42	$0.25	$0.38	$29.92	$30.13	($0.27)	$0.05
PECO	$58.38	$54.37	$2.52	$1.49	$26.19	$30.22	($3.87)	($0.17)
PEPCO	$64.19	$55.17	$7.06	$1.95	$33.01	$30.49	$1.67	$0.86
PPL	$55.23	$54.36	$0.14	$0.73	$27.64	$30.23	($2.28)	($0.31)
PSEG	$64.47	$53.71	$8.41	$2.35	$27.70	$30.17	($2.84)	$0.37
REC	$68.72	$53.48	$12.91	$2.33	$29.21	$30.18	($1.32)	$0.34
PJM	$54.13	$54.03	$0.06	$0.04	$30.28	$30.23	$0.02	$0.02

The day-ahead components of LMP for each control zone are presented in Table 11-5 for January through March, 2022 and 2023. In the first three months of 2023, BGE had the highest day-ahead congestion component of all control zones, $4.50, and PECO had the lowest day-ahead congestion component, -$4.15.

Table 11-5 Zonal day-ahead load-weighted average LMP components (Dollars per MWh): January through March, 2022 and 2023

	2022 (Jan - Mar)				2023 (Jan - Mar)			
	Day-Ahead LMP	Energy Component	Congestion Component	Loss Component	Day-Ahead LMP	Energy Component	Congestion Component	Loss Component
ACEC	$54.34	$53.54	($2.12)	$2.92	$29.24	$32.17	($3.24)	$0.30
AEP	$50.91	$53.14	($0.96)	($1.27)	$32.12	$32.01	$0.39	($0.27)
APS	$54.42	$53.68	$0.52	$0.22	$33.68	$32.27	$1.21	$0.19
ATSI	$49.92	$52.56	($2.22)	($0.42)	$32.11	$31.84	$0.22	$0.06
BGE	$63.15	$53.95	$6.34	$2.85	$38.41	$32.53	$4.50	$1.38
COMED	$41.12	$52.23	($8.00)	($3.11)	$27.24	$31.72	($2.99)	($1.49)
DAY	$52.02	$52.88	($0.88)	$0.01	$33.57	$32.06	$0.67	$0.84
DOM	$62.77	$54.02	$7.67	$1.07	$36.06	$32.28	$3.06	$0.72
DPL	$63.12	$54.85	$3.90	$4.37	$31.37	$32.83	($2.56)	$1.10
DUKE	$50.89	$52.97	($0.15)	($1.94)	$32.76	$32.06	$0.74	($0.04)
DUQ	$48.19	$52.82	($3.05)	($1.58)	$31.46	$31.92	($0.07)	($0.39)
EKPC	$52.57	$54.41	$0.29	($2.13)	$32.83	$32.71	$0.58	($0.46)
JCPLC	$55.98	$53.38	($0.67)	$3.27	$29.76	$32.30	($3.04)	$0.49
MEC	$60.95	$53.36	$5.29	$2.30	$32.64	$32.34	$0.10	$0.19
OVEC	$46.04	$48.04	$0.18	($2.17)	$27.70	$26.54	$1.46	($0.30)
PE	$57.50	$53.64	$2.62	$1.23	$33.48	$32.51	$0.81	$0.16
PECO	$54.10	$53.42	($1.60)	$2.28	$27.99	$32.18	($4.15)	($0.04)
PEPCO	$62.74	$54.29	$6.14	$2.31	$37.55	$32.66	$3.74	$1.16
PPL	$55.49	$53.33	$0.60	$1.56	$29.99	$32.14	($1.93)	($0.21)
PSEG	$59.02	$52.98	$2.63	$3.40	$30.50	$32.28	($2.32)	$0.54
REC	$65.92	$54.82	$7.71	$3.39	$34.46	$33.43	$0.40	$0.64
PJM	$54.23	$53.26	$0.63	$0.34	$32.16	$32.12	($0.01)	$0.05

Hub Components

The real-time components of LMP for each hub are presented in Table 11-6 for January through March, 2022 and 2023.[11]

Table 11-6 Hub real-time average LMP components (Dollars per MWh): January through March, 2022 and 2023

	2022 (Jan - Mar)				2023 (Jan - Mar)			
	Real-Time LMP	Energy Component	Congestion Component	Loss Component	Real-Time LMP	Energy Component	Congestion Component	Loss Component
AEP Gen Hub	$45.04	$51.86	($4.40)	($2.42)	$29.19	$29.53	$0.52	($0.85)
AEP-DAY Hub	$46.11	$51.86	($4.37)	($1.38)	$29.60	$29.53	$0.36	($0.29)
ATSI Gen Hub	$45.52	$51.86	($4.90)	($1.44)	$29.05	$29.53	$0.03	($0.51)
Chicago Gen Hub	$37.40	$51.86	($10.56)	($3.90)	$25.98	$29.53	($1.97)	($1.58)
Chicago Hub	$38.31	$51.86	($10.35)	($3.20)	$26.43	$29.53	($1.90)	($1.20)
Dominion Hub	$59.06	$51.86	$6.86	$0.34	$31.57	$29.53	$1.87	$0.17
Eastern Hub	$60.45	$51.86	$5.86	$2.73	$28.46	$29.53	($1.61)	$0.55
N Illinois Hub	$38.03	$51.86	($10.38)	($3.45)	$26.26	$29.53	($1.92)	($1.36)
New Jersey Hub	$58.44	$51.86	$4.59	$1.99	$26.90	$29.53	($2.90)	$0.26
Ohio Hub	$45.89	$51.86	($4.57)	($1.40)	$29.47	$29.53	$0.23	($0.29)
West Interface Hub	$49.24	$51.86	($1.68)	($0.95)	$30.16	$29.53	$0.95	($0.32)
Western Hub	$53.03	$51.86	$0.77	$0.40	$30.13	$29.53	$0.43	$0.18

The day-ahead components of LMP for each hub are presented in Table 11-7 for January through March, 2022 and 2023.

Table 11-7 Hub day-ahead average LMP components (Dollars per MWh): January through March, 2022 and 2023

	2022 (Jan - Mar)				2023 (Jan - Mar)			
	Day-Ahead LMP	Energy Component	Congestion Component	Loss Component	Day-Ahead LMP	Energy Component	Congestion Component	Loss Component
AEP Gen Hub	$47.51	$51.38	($1.34)	($2.53)	$30.64	$31.24	$0.30	($0.90)
AEP-DAY Hub	$48.46	$51.38	($1.43)	($1.49)	$31.05	$31.24	$0.19	($0.38)
ATSI Gen Hub	$48.11	$51.38	($2.04)	($1.23)	$30.83	$31.24	$0.10	($0.51)
Chicago Gen Hub	$39.68	$51.38	($8.15)	($3.56)	$26.47	$31.24	($3.01)	($1.76)
Chicago Hub	$40.53	$51.38	($7.93)	($2.92)	$26.89	$31.24	($2.96)	($1.39)
Dominion Hub	$58.42	$51.38	$6.89	$0.15	$33.69	$31.24	$2.19	$0.26
Eastern Hub	$56.31	$51.38	$1.12	$3.80	$29.50	$31.24	($2.61)	$0.87
N Illinois Hub	$40.17	$51.38	($8.02)	($3.20)	$26.72	$31.24	($2.96)	($1.56)
New Jersey Hub	$54.61	$51.38	$0.24	$2.99	$28.83	$31.24	($2.80)	$0.39
Ohio Hub	$48.33	$51.38	($1.53)	($1.52)	$30.92	$31.24	$0.09	($0.41)
West Interface Hub	$50.66	$51.38	$0.13	($0.85)	$32.05	$31.24	$1.08	($0.26)
Western Hub	$55.58	$51.38	$2.97	$1.23	$33.13	$31.24	$1.57	$0.32

11 The real-time components of LMP are the simple average of the hourly components for each hub. Some hubs include only generation buses and do not include load buses. The real-time components of LMP were previously reported as the real-time, load-weighted, average of the hourly components of LMP.

Congestion

Congestion Accounting

In PJM accounting, total congestion costs equal net implicit CLMP charges, plus net explicit CLMP charges, plus net inadvertent CLMP charges. Implicit CLMP charges equal implicit withdrawal charges less implicit injection credits. Explicit CLMP charges are the net CLMP charges associated with the injection credits and withdrawal charges for point to point energy transactions. Inadvertent CLMP charges are not directly attributable to specific participants that are distributed on a load ratio basis. Each of these categories of congestion costs is comprised of day-ahead and balancing congestion costs.

While PJM accounting focuses on CLMPs, the individual CLMP values at any bus are irrelevant to the calculation of congestion, as CLMPs are just an artificial deconstruction of LMP based on a selected reference bus. Holding aside the marginal loss component of LMP, differences in the LMPs are caused by binding constraints in the least cost security constrained dispatch market solution and total congestion is the net surplus revenue that remains after all sources and sinks are credited or charged their LMPs. Changing the components of LMP by electing a different reference bus does not change the LMPs or the difference between LMPs for a given market solution or actual congestion, it merely changes the components of the LMP.

Congestion occurs in the day-ahead and real-time energy markets.[12] Day-ahead congestion costs are based on day-ahead MWh while balancing congestion costs are based on deviations between day-ahead and real-time MWh priced at the congestion price in the real-time energy market.

Implicit CLMP charges are the CLMP charges calculated for energy injected or withdrawn at a location. The explicit CLMP charges are the CLMP charges calculated for transactions with a defined source and a sink. For example, implicit CLMP charges are calculated for network load and explicit CLMP charges are calculated for up to congestion transactions (UTCs). Inadvertent CLMP charges are CLMP charges resulting from the differences between the net actual energy flow and the net scheduled energy flow into or out of the PJM control area each hour.

CLMP charges and CLMP credits are calculated for both the day-ahead and balancing energy markets.

- **Day-Ahead Implicit Load CLMP Charges.** Day-ahead implicit withdrawal charges are calculated for all cleared demand, decrement bids and day-ahead energy market sale transactions. Day-ahead implicit withdrawal charges are calculated using MW and the load bus CLMP, the decrement bid CLMP or the CLMP at the source of the sale transaction.
- **Day-Ahead Implicit Generation CLMP Credits.** Day-ahead implicit injection credits are calculated for all cleared generation, increment offers and day-ahead energy market purchase transactions.[13] Day-ahead implicit injection credits are calculated using MW and the generator bus CLMP, the increment offer's CLMP or the CLMP at the sink of the purchase transaction.
- **Balancing Implicit Load CLMP Charges.** Balancing implicit withdrawal charges are calculated for all deviations between a PJM member's real-time load and energy sale transactions and their day-ahead cleared demand, decrement bids and energy sale transactions. Balancing implicit withdrawal charges are calculated using MW deviations and the real-time CLMP for each aggregate where a deviation exists.
- **Balancing Implicit Generation CLMP Credits.** Balancing implicit injection credits are calculated for all deviations between a PJM member's real-time generation and energy purchase transactions and the day-ahead cleared generation, increment offers and energy purchase transactions. Balancing implicit injection credits are calculated using MW deviations and the real-time CLMP for each aggregate where a deviation exists.

12 When the term *congestion charge* is used in documents by PJM's Market Settlement Operations, it has the same meaning as the term *congestion costs* as used here.

13 Internal bilateral transactions are included in the tariff definitions of Market Participant Energy Injections and Market Participant Energy Withdrawals. The purchase part of an internal bilateral transaction is an injection to the buyer and the sale part of an internal bilateral transaction is a withdrawal to the seller. The tariff (Attachment K) also says market participants will be charged implicit CLMP charges for all Market Participant Energy Withdrawals and will be credited implicit CLMP credits for all Market Participant Energy Injections. The seller of an internal bilateral transaction will be charged implicit CLMP charges at the source and the buyer of an internal bilateral transaction will be credited implicit CLMP credits at the sink. Internal bilateral transaction CLMP credits and charges sum to zero, as the IBT is merely a transfer of ownership injection and withdrawal MW and associated charges and credits between participants, meaning that the sum of all MW and all credits and all charges with and without IBTs are the same.

- **Explicit CLMP Charges.** Explicit CLMP charges are the net CLMP costs associated with point to point energy transactions. Day-ahead explicit CLMP charges equal the product of the transacted MW and CLMP differences between sources (origins) and sinks (destinations) in the day-ahead energy market. Balancing explicit CLMP charges equal the product of the deviations between the real-time and day-ahead transacted MW and the differences between the real-time CLMP at the transactions' sources and sinks. Explicit CLMP charges are calculated for internal purchase, import and export transaction, and up to congestion transactions (UTCs.)
- **Inadvertent CLMP Charges.** Inadvertent CLMP charges are charges resulting from the differences between the net actual energy flow and the net scheduled energy flow into or out of the PJM control area each hour. This inadvertent interchange of energy may be positive or negative, where positive interchange typically results in a charge while negative interchange typically results in a credit. Inadvertent CLMP charges are common costs, not directly attributable to specific participants that are distributed on a load ratio basis.[14]

The congestion accounting calculation equations are in Table 11-8.

Table 11-8 Congestion accounting calculations

Congestion Category	Calculation
Day-Ahead Implicit Withdrawal CLMP Charges	Day-Ahead Demand MWh * Day-Ahead CLMP
Day-Ahead Implicit Injection CLMP Credits	Day-Ahead Supply MWh * Day-Ahead CLMP
Day-Ahead Explicit CLMP Charges	Day-Ahead Transaction MW * (Day-Ahead Sink CLMP - Day-Ahead Source CLMP)
Day-Ahead Total Congestion Costs	Day-Ahead Implicit Withdrawal CLMP Charges - Day-Ahead Implicit Injection CLMP Credits + Day-Ahead Explicit CLMP Charges
Balancing Implicit Withdrawal CLMP Charges	Balancing Demand MWh * Real-Time CLMP
Balancing Implicit Injection CLMP Credits	Balancing Supply MWh * Real-Time CLMP
Balancing Explicit CLMP Costs	Balancing Transaction MW * (Real-Time Sink CLMP - Real-Time Source CLMP)
Balancing Total Congestion Costs	Balancing Implicit Withdrawal CLMP Charges - Balancing Implicit Injection CLMP Credits + Balancing Explicit CLMP Costs
Total Congestion Costs	Day-Ahead Total Congestion Costs + Balancing Total Congestion Costs

MWh Category	Definition
Day-Ahead Demand MWh	Cleared Demand, Decrement Bids, Energy Sale Transactions
Day-Ahead Supply MWh	Cleared Generation, Increment Bids, Energy Purchase Transactions
Real-Time Demand MWh	Load and Energy Sale Transactions
Real-Time Supply MWh	Generation and Energy Purchase Transactions
Balancing Demand MWh	Real-Time Demand MWh - Day-Ahead Demand MWh
Balancing Supply MWh	Real-Time Supply MWh - Day-Ahead Supply MWh

PJM billing items include Day-Ahead Transmission Congestion Charges, Day-Ahead Transmission Congestion Credits, Balancing Transmission Congestion Charges, and Balancing Transmission Congestion Credits. Those line items are calculated for each PJM member. The congestion bill shows the CLMP charges or credits collected from the PJM market participants. However, the sum of an individual customer's CLMP credits or charges on the customer's bill is not a measure of the congestion paid by that customer.

14 PJM Operating Agreement Schedule 1 §3.7.

The congestion paid by a customer is the difference between what the customer paid for energy and what all network sources of that energy were paid to serve that customer. A load customer's congestion bill, in contrast, merely indicates whether the LMP they paid for their withdrawals is higher or lower than the system energy price due to transmission constraints. The customer's bill does not measure congestion paid by the customer, only how much the customer was charged and credited for their MW positions. The congestion costs associated with specific constraints are the sum of the total day-ahead and balancing congestion costs associated with those constraints. Zonal congestion is calculated on a constraint by constraint basis. The congestion calculations are the total difference between what the zonal load pays in CLMP charges and what the generation that serves that load is paid, regardless of whether the zone is a net importer or a net exporter of generation. Congestion costs can be both positive and negative and CLMP charges and CLMP credits can be both positive and negative. CLMP charges, positive or negative, are paid by withdrawals and CLMP credits, positive or negative, are paid to injections. Total congestion costs (the sum of charges and credits), when positive, measure the net congestion payment by a participant group and when negative, measure the net congestion credit paid to a participant group. Explicit CLMP charges, when positive, measure the congestion payment to a PJM member and when negative, measure the congestion credit paid to a PJM member. Explicit CLMP charges are calculated for up to congestion transactions (UTCs).

The congestion accounting definitions are misleading. Load pays congestion. Congestion is the difference between what load pays for energy and what generation is paid for energy due to binding transmission constraints. Generation does not pay congestion. Some generation receives a price lower than SMP and some generation receives a price greater than SMP but that does not mean that generation is paying congestion. It means only that generation is being paid an LMP that is higher or lower than the system load-weighted average LMP.

The CLMP is calculated with respect to the LMP at the system reference bus, also called the system marginal price (SMP). When a transmission constraint occurs, the resulting CLMP is positive on one side of the constraint and negative on the other side of the constraint and the corresponding congestion costs are positive or negative. For each transmission constraint, the CLMP reflects the cost of a constraint at a pricing node and is equal to the product of the constraint shadow price and the distribution factor from the constraint to the pricing node. The total CLMP at a pricing node is the sum of all constraint contributions to LMP and is equal to the difference between the actual LMP that results from transmission constraints, excluding losses, and the SMP. If an area experiences lower prices because of a constraint, the CLMP in that area is negative.[15]

Load-weighted LMP components are calculated relative to a load-weighted, average LMP. At the load-weighted reference bus, which represents the load center of the system, the LMP calculation is designed to include no congestion or loss components, but it may include congestion. The load weighted average CLMP across all load buses, calculated relative to that reference bus, is equal to, or very close to, zero, with non-zero results caused by state estimator error and after the fact meter updates. The sum of load related CLMP charges is logically zero and the small reported differences are the result of accounting issues. A positive CLMP at a load bus indicates that the load at that bus has a total energy price higher than the average LMP, due to transmission constraints. A negative CLMP at a load bus indicates that the load at that bus has a total energy price lower than the average LMP, due to transmission constraints. The LMPs at the load buses are a function of marginal generation bus LMPs determined through the least cost security constrained economic dispatch which accounts for transmission constraints and marginal losses. Due to transmission constraints, the average generation weighted CLMP for generation resources is lower than the LMP at the load-weighted reference bus price. Calculated relative to the load reference bus which has a CLMP of zero, this means that the average of the generation bus CLMPs is negative. This means that total generation CLMP credits are negative.

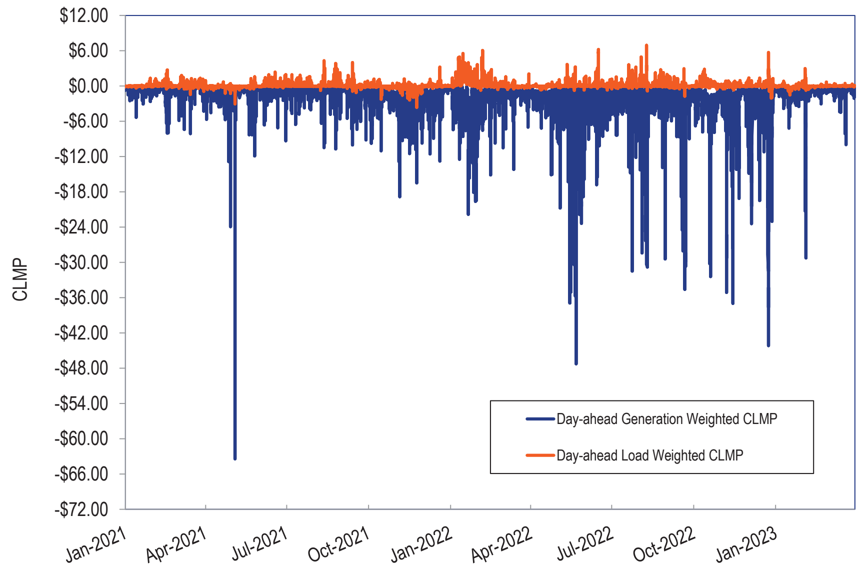
Figure 11-1 shows the weighted average CLMPs of generation and load in the day-ahead market. Figure 11-1 shows that in January 2022 through March

15 For an example of the congestion accounting methods used in this section, see *MMU Technical Reference for PJM Markets*, at "FTRs and ARRs," <http://www.monitoringanalytics.com/reports/Technical_References/docs/2010-som-pjm-technical-reference.pdf>.

2023, day-ahead generation weighted CLMPs were generally negative and day-ahead, load weighted CLMPs were generally positive, indicating that load was charged a higher weighted average LMP for energy as a result of transmission constraints than the weighted average LMP generation was paid to provide that energy. This means that total CLMP load payments are higher than total CLMP generation credits. The difference in load payments and generation credits (load charges minus generation credits) is congestion (Table 11-11 and Table 11-12). This result is a product of the least cost, security constrained dispatch and the use of a load-weighted reference bus that is used for the determination of the components of LMP. More generally, in a least cost, security constrained market solution the weighted average LMP at load buses is higher than the weighted average price at generation buses.

The day-ahead, generation weighted CLMPs were significantly negative for two hours on May 4, 2021, due to high shadow prices of two constraints caused by a transmission outage in the DOM Zone. The day-ahead generation weighted CLMPs were significantly negative for three hours on May 22, 2022 due to transmission constraint violations in HE 1400, HE 1700 and HE 1800. The day-ahead generation weighted CLMPs were significantly negative for two hours on September 21, 2022, due to transmission constraint violations in HE 1600 and HE 1700 on the Brambleton - Evergreen Mills Line.

Figure 11-1 Day-ahead generation weighted CLMPs and day-ahead load-weighted CLMPs: January 2021 through March 2023



Total Congestion

Total congestion costs in PJM in the first three months of 2023 were $175.5 million, comprised of implicit withdrawal charges of $56.7 million, minus implicit injection credits of -$144.9 million, and plus explicit charges of -$26.1 million. Total congestion is the difference between what load pays for energy and what generation is paid for energy, due to binding transmission constraints.

Table 11-9 shows total congestion for January through March, 2008 through 2023. Total congestion costs in Table 11-9 include congestion associated with PJM facilities and those associated with reciprocal, coordinated flowgates in MISO and in NYISO.[16] [17]

16 See "Joint Operating Agreement Between the Midwest Independent Transmission System Operator, Inc. and PJM Interconnection, L.L.C.," (December 11, 2008) Section 6.1, Effective Date: May 30, 2016. <http://www.pjm.com/documents/agreements.aspx>.

17 See "NYISO Tariffs New York Independent System Operator, Inc.," (June 21, 2017) 35.12.1, Effective Date: May 1, 2017. <http://www.pjm.com/documents/agreements.aspx>.

Table 11-9 Total congestion costs (Dollars (Millions)): January through March, 2008 through 2023[18]

(Jan - Mar)	Congestion Cost	Percent Change	Total PJM Billing	Percent of PJM Billing
2008	$486	NA	$7,718	6.3%
2009	$307	(36.8%)	$7,515	4.1%
2010	$345	12.4%	$8,415	4.1%
2011	$360	4.3%	$9,584	3.8%
2012	$122	(66.0%)	$6,938	1.8%
2013	$186	51.9%	$7,762	2.4%
2014	$1,236	564.8%	$21,070	5.9%
2015	$632	(48.9%)	$14,040	4.5%
2016	$292	(53.7%)	$9,500	3.1%
2017	$158	(45.9%)	$9,710	1.6%
2018	$661	318.4%	$14,520	4.6%
2019	$164	(75.2%)	$11,600	1.4%
2020	$85	(48.1%)	$8,740	1.0%
2021	$121	42.2%	$11,280	1.1%
2022	$510	321.5%	$18,100	2.8%
2023	$175	(65.6%)	$12,030	1.5%

CLMP charges and credits are not congestion. CLMP charges and credits reflect marginal energy price differences caused by binding system constraints. Congestion is the sum of all congestion related charges and credits. In a two settlement system all virtual bids have net zero MW after their day-ahead and balancing positions are cleared, which means that virtual bids are fully settled in terms of CLMP credits and charges at the close of the market for any particular day, with either a net loss or profit due to differences between day-ahead and real-time prices. Net payouts (negative credits) to virtual bids appear as negative adjustments to either day-ahead or balancing congestion and net charges to virtual bids appear as positive adjustments to either day-ahead or balancing congestion.

Table 11-10 shows total congestion by day-ahead and balancing component for January through March, 2008 through 2023.

18 In Table 11-9, the MMU uses Total PJM Billing values provided by PJM. For 2019 and after, the Total PJM Billing calculation was modified to better reflect PJM total billing through the PJM settlement process.

Table 11-10 Total CLMP credits and charges by accounting category (Dollars (Millions)): January through March, 2008 through 2023

	CLMP Credits and Charges (Millions)									
	Day-Ahead				Balancing					
(Jan - Mar)	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Inadvertent Charges	Congestion Costs
2008	$332.4	($220.0)	$39.9	$592.3	($46.0)	$29.5	($31.2)	($106.7)	$0.0	$485.6
2009	$120.2	($221.3)	$47.9	$389.5	($14.2)	($6.0)	($74.4)	($82.6)	($0.0)	$306.9
2010	$85.9	($293.1)	$12.9	$391.9	($5.7)	$12.1	($29.1)	($47.0)	($0.0)	$344.9
2011	$176.5	($226.7)	$4.1	$407.3	$21.6	$27.8	($41.2)	($47.4)	$0.0	$359.9
2012	$21.9	($131.4)	$27.5	$180.9	($5.1)	$11.3	($42.0)	($58.4)	$0.0	$122.4
2013	$85.0	($199.1)	$47.8	$331.9	($6.6)	$73.3	($66.0)	($145.9)	$0.0	$185.9
2014	$333.7	($1,193.9)	($94.3)	$1,433.3	$73.0	$208.9	($61.3)	($197.2)	$0.0	$1,236.1
2015	$327.0	($457.9)	($11.0)	$773.9	$5.4	$69.6	($78.0)	($142.2)	($0.0)	$631.7
2016	$120.2	($193.5)	$9.2	$322.9	($1.1)	$11.9	($17.7)	($30.8)	$0.0	$292.2
2017	$24.2	($137.7)	$3.0	$164.9	($0.3)	$7.5	$0.9	($6.9)	($0.0)	$158.0
2018	$130.9	($557.5)	($46.7)	$641.7	$12.8	$23.6	$30.1	$19.3	$0.0	$661.0
2019	$53.3	($137.7)	$11.2	$202.2	($1.8)	$20.1	($16.4)	($38.3)	$0.0	$163.9
2020	$13.5	($75.7)	$14.1	$103.3	($0.2)	$3.8	($14.2)	($18.2)	($0.0)	$85.1
2021	$82.3	($123.5)	$18.7	$224.5	($26.7)	$39.9	($36.8)	($103.4)	$0.0	$121.1
2022	$304.6	($364.6)	$32.2	$701.4	($46.4)	$79.6	($65.1)	($191.2)	$0.0	$510.3
2023	$53.7	($151.9)	$20.6	$226.2	$2.9	$7.0	($46.7)	($50.8)	$0.0	$175.5

Charges and Credits versus Congestion: Virtual Transactions, Load and Generation

In PJM's two settlement system, there is a day-ahead market and a real-time, balancing market, that make up a market day.

In a two settlement system all virtual bids have net zero MW after their day-ahead and balancing positions are cleared, which means that virtual bids are fully settled in terms of CLMP credits and charges at the close of each market day, with either a net loss or profit due to differences between day-ahead and real-time prices. Net payouts (negative credits) to virtual bids appear as negative adjustments to either day-ahead or balancing congestion and net charges to virtual bids appear as positive adjustments to either day-ahead or balancing congestion.

Unlike virtual bids, physical load and generation have net MW at the close of a market day's day-ahead and balancing settlement.

Generation does not pay congestion. Some generation receives a price lower than SMP and some generation receives a price greater than SMP but that does not mean that generation is paying congestion. It means that generation is being paid an LMP that is higher or lower than the system load-weighted, average LMP.

The residual difference between total load charges (day-ahead and balancing) and generation credits (day-ahead and balancing) after virtual bids have settled their day-ahead and balancing positions is congestion. That is, congestion is the difference between what withdrawals (load) pay for energy and what injections (generation) are paid for energy due to binding transmission constraints, after virtual bids are settled at the end of the market day. Load is the source of the net surplus after generation is paid and virtuals are settled at the end of the market day. Load pays congestion.

Table 11-11 and Table 11-12 show the total CLMP charges and credits for each transaction type in the first three months of 2023 and 2022. Table 11-11 shows that in the first three months of 2023 DECs paid $0.8 million in CLMP charges in the day-ahead market, were paid $0.6 million in CLMP credits in the balancing energy market, resulting in a net charge of $0.2 million. In the first three months of 2023, INCs paid $10.5 million in CLMP charges in the day-ahead market, were paid $10.4 million in CLMP credits in the balancing energy market resulting in a net charge of $0.1 million. In the first three months of 2023, up to congestion (UTCs) paid $20.6 million in CLMP charges in the day-ahead market, were paid $46.2 million in CLMP credits in the balancing market resulting in a total payment of $25.6 million in total CLMP credits.

Table 11-11 Total CLMP credits and charges by transaction type (Dollars (Millions)): January through March, 2023

	CLMP Credits and Charges (Millions)									
	Day-Ahead				Balancing					
Transaction Type	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Inadvertent Charges	Grand Total
DEC	$0.8	$0.0	$0.0	$0.8	($0.6)	$0.0	$0.0	($0.6)	$0.0	$0.2
Demand	($3.7)	$0.0	$0.0	($3.7)	$8.1	$0.0	$0.0	$8.1	$0.0	$4.4
Demand Response	($0.0)	$0.0	$0.0	($0.0)	$0.0	$0.0	$0.0	$0.0	$0.0	($0.0)
Explicit Congestion Only	$0.0	$0.0	$0.1	$0.1	$0.0	$0.0	($0.0)	($0.0)	$0.0	$0.1
Explicit Congestion and Loss Only	$0.0	$0.0	($0.2)	($0.2)	$0.0	$0.0	($0.0)	($0.0)	$0.0	($0.3)
Export	($7.5)	$0.0	($0.1)	($7.6)	($2.0)	$0.0	($0.3)	($2.4)	$0.0	($10.0)
Generation	$0.0	($205.4)	$0.0	$205.4	$0.0	($2.4)	$0.0	$2.4	$0.0	$207.8
Import	$0.0	($0.5)	$0.0	$0.5	$0.0	$1.6	$0.0	($1.6)	$0.0	($1.2)
INC	$0.0	($10.5)	$0.0	$10.5	$0.0	$10.4	$0.0	($10.4)	$0.0	$0.1
Internal Bilateral	$64.2	$64.5	$0.3	($0.0)	($2.6)	($2.6)	$0.0	$0.0	$0.0	$0.0
Up to Congestion	$0.0	$0.0	$20.6	$20.6	$0.0	$0.0	($46.2)	($46.2)	$0.0	($25.6)
Wheel In	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	($0.1)	($0.2)	$0.0	($0.2)
Wheel Out	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Total	$53.7	($151.9)	$20.6	$226.2	$2.9	$7.0	($46.7)	($50.8)	$0.0	$175.5

Table 11-12 Total CLMP credits and charges by transaction type (Dollars (Millions)): January through March, 2022

	CLMP Credits and Charges (Millions)									
	Day-Ahead				Balancing					
Transaction Type	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Inadvertent Charges	Grand Total
DEC	$32.4	$0.0	$0.0	$32.4	($69.8)	$0.0	$0.0	($69.8)	$0.0	($37.3)
Demand	$98.5	$0.0	$0.0	$98.5	$16.7	$0.0	$0.0	$16.7	$0.0	$115.2
Demand Response	($0.0)	$0.0	$0.0	($0.0)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Explicit Congestion Only	$0.0	$0.0	$0.2	$0.2	$0.0	$0.0	($0.0)	($0.0)	$0.0	$0.2
Explicit Congestion and Loss Only	$0.0	$0.0	($0.6)	($0.6)	$0.0	$0.0	$0.0	$0.0	$0.0	($0.6)
Export	$9.3	$0.0	($0.1)	$9.1	$11.6	$0.0	$2.7	$14.3	$0.0	$23.4
Generation	$0.0	($511.7)	$0.0	$511.7	$0.0	$42.5	$0.0	($42.5)	$0.0	$469.2
Import	$0.0	($0.3)	$0.0	$0.3	$0.0	$3.6	$0.0	($3.6)	$0.0	($3.3)
INC	$0.0	($17.2)	$0.0	$17.2	$0.0	$38.6	$0.0	($38.6)	$0.0	($21.4)
Internal Bilateral	$164.4	$164.5	$0.1	$0.0	($4.8)	($4.8)	$0.0	($0.0)	$0.0	($0.0)
Up to Congestion	$0.0	$0.0	$32.6	$32.6	$0.0	$0.0	($67.2)	($67.2)	$0.0	($34.6)
Wheel In	$0.0	$0.0	$0.0	$0.0	$0.0	($0.3)	($0.6)	($0.3)	$0.0	($0.3)
Wheel Out	$0.0	$0.0	$0.0	$0.0	($0.3)	$0.0	$0.0	($0.3)	$0.0	($0.3)
Total	$304.6	($364.6)	$32.2	$701.4	($46.4)	$79.6	($65.1)	($191.2)	$0.0	$510.3

Table 11-13 shows the change in total CLMP credits and charges by transaction type in January through March, 2022 to 2023. Total negative CLMP credits to generation decreased by $261.4 million, and total CLMP charges to demand decreased by $110.8 million. The total CLMP credits to up to congestion transactions (UTCs) decreased by $9.0 million in the first three months of 2023. Total day-ahead CLMP charges to UTCs decreased by $12.0 million in the first three months of 2023. Balancing CLMP credits to UTCs decreased by $21.0 million in the first three months of 2023.

Table 11-13 Change in total CLMP credits and charges by transaction type (Dollars (Millions)): January through March, 2022 to 2023

	Change in CLMP Credits and Charges (Millions)									
	Day-Ahead				Balancing					
Transaction Type	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Inadvertent Charges	Grand Total
DEC	($31.7)	$0.0	$0.0	($31.7)	$69.2	$0.0	$0.0	$69.2	$0.0	$37.5
Demand	($102.2)	$0.0	$0.0	($102.2)	($8.6)	$0.0	$0.0	($8.6)	$0.0	($110.8)
Demand Response	($0.0)	$0.0	$0.0	($0.0)	($0.0)	$0.0	$0.0	($0.0)	$0.0	($0.0)
Explicit Congestion Only	$0.0	$0.0	($0.1)	($0.1)	$0.0	$0.0	$0.0	$0.0	$0.0	($0.1)
Explicit Congestion and Loss Only	$0.0	$0.0	$0.4	$0.4	$0.0	$0.0	($0.0)	($0.0)	$0.0	$0.3
Export	($16.8)	$0.0	$0.0	($16.8)	($13.6)	$0.0	($3.0)	($16.7)	$0.0	($33.4)
Generation	$0.0	$306.3	$0.0	($306.3)	$0.0	($44.9)	$0.0	$44.9	$0.0	($261.4)
Import	$0.0	($0.2)	$0.0	$0.2	$0.0	($1.9)	$0.0	$1.9	$0.0	$2.1
INC	$0.0	$6.7	$0.0	($6.7)	$0.0	($28.2)	$0.0	$28.2	$0.0	$21.5
Internal Bilateral	($100.2)	($100.1)	$0.2	($0.0)	$2.2	$2.2	$0.0	$0.0	$0.0	$0.0
Up to Congestion	$0.0	$0.0	($12.0)	($12.0)	$0.0	$0.0	$21.0	$21.0	$0.0	$9.0
Wheel In	$0.0	$0.0	$0.0	$0.0	$0.0	$0.3	$0.5	$0.2	$0.0	$0.2
Wheel Out	$0.0	$0.0	$0.0	$0.0	$0.3	$0.0	$0.0	$0.3	$0.0	$0.3
Total	($250.9)	$212.8	($11.6)	($475.2)	$49.4	($72.6)	$18.4	$140.4	$0.0	($334.8)

Table 11-14 compares CLMP credits and charges for each transaction type between the dispatch run and pricing run in the first three months of 2023. Total CLMP charges to generation decreased by $0.2 million, and total CLMP charges to demand increased by $0.3 million from the dispatch run to the pricing run. The total CLMP charges to DECs decreased by $0.7 million, the total CLMP credits to INCs decreased by $0.2 million and the total CLMP credits to UTCs increased by $4.6 million from the dispatch run to the pricing run.

Table 11-14 Total CLMP credits and charges by dispatch run and pricing run (Dollars (Millions)): January through March, 2023

	CLMP Credits and Charges (Millions)								
	Dispatch Run			Pricing Run			Difference		
Transaction Type	Day-Ahead	Balancing	Total	Day-Ahead	Balancing	Total	Day-Ahead	Balancing	Total
DEC	$1.0	($0.1)	$0.9	$0.8	($0.6)	$0.2	($0.2)	($0.5)	($0.7)
Demand	($3.5)	$7.6	$4.1	($3.7)	$8.1	$4.4	($0.2)	$0.5	$0.3
Demand Response	($0.0)	$0.0	($0.0)	($0.0)	$0.0	($0.0)	($0.0)	$0.0	$0.0
Explicit Congestion Only	$0.1	($0.0)	$0.1	$0.1	($0.0)	$0.1	$0.0	($0.0)	$0.0
Explicit Congestion and Loss Only	($0.3)	($0.0)	($0.3)	($0.2)	($0.0)	($0.3)	$0.1	($0.0)	$0.1
Export	($7.4)	($2.3)	($9.7)	($7.6)	($2.4)	($10.0)	($0.2)	($0.1)	($0.3)
Generation	$205.2	$2.8	$208.0	$205.4	$2.4	$207.8	$0.2	($0.4)	($0.2)
Import	$0.5	($1.6)	($1.1)	$0.5	($1.6)	($1.2)	($0.0)	($0.0)	($0.1)
INC	$10.4	($10.5)	($0.1)	$10.5	($10.4)	$0.1	$0.1	$0.1	$0.2
Internal Bilateral	$0.0	$0.0	$0.0	($0.0)	$0.0	$0.0	($0.0)	$0.0	$0.0
Up to Congestion	$20.2	($41.2)	($21.0)	$20.6	($46.2)	($25.6)	$0.4	($5.0)	($4.6)
Wheel In	$0.0	($0.2)	($0.2)	$0.0	($0.2)	($0.2)	$0.0	($0.0)	($0.0)
Wheel Out	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Total	$226.2	($45.4)	$180.8	$226.2	($50.8)	$175.5	$0.1	($5.4)	($5.3)

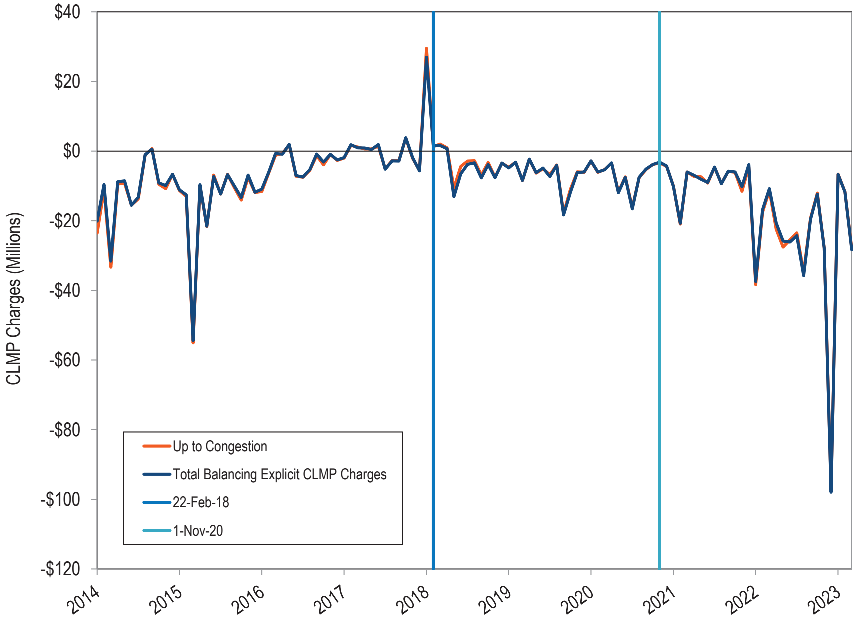
UTCs and Negative Balancing Explicit CLMP Charges

Figure 11-2 shows the change in up to congestion balancing explicit CLMP charges from January 2014 through March 2022. Figure 11-2 shows that UTCs account for almost all balancing explicit CLMP charges in PJM. As shown in Figure 11-2, UTCs are generally paid balancing CLMP credits, which take the form of negative balancing CLMP charges being allocated to UTC positions. In the first three months of 2023, 99.0 percent (-$46.2 million out of -$46.7 million) of negative balancing explicit CLMP charges was incurred by UTCs and 1.0 percent (-$0.5 out of -$46.7 million) was incurred by Explicit Congestion Only, Export, Import and Wheel In transactions (Table 11-11). The vertical line at February 22, 2018, marks the date on which the FERC order that limited UTC trading to hubs, residual metered load, and interfaces was effective.[19] The vertical line at November 1, 2020, marks the date on which the FERC order that required PJM to allocate uplift to up to congestion transactions was effective.[20]

Negative balancing explicit CLMP charges were substantially higher in December than in other months as a result of transmission constraint penalty factors in the real-time market in 2022. The total negative balancing explicit CLMP charges on December 7 and 8, and the Elliott days of December 23 through 26, 2022 were 64.1 percent (-$62.3 million out of -$97.2 million) of total negative balancing explicit CLMP charges in December of 2022.

19 For additional information about the FERC order, see the *2023 State of the Market Report for PJM*, Appendix F: Congestion and Marginal Losses.
20 172 FERC ¶ 61,046 (2020).

Figure 11-2 Monthly balancing explicit CLMP charges incurred by UTC: January 2014 through March 2023



Balancing congestion is caused by settling real-time deviations from day-ahead positions at real-time prices. Whether balancing congestion is positive or negative depends on the differences between the day-ahead and real-time market models including modeled constraints, the transfer capability (line limits) of the modeled constraints and the differences in deviations between day-ahead and real-time flows that result. The deviations are priced at the real-time LMPs.

For example, one source of negative balancing congestion is that the PJM system has less transmission transfer capability in the real-time market than is modeled in the day-ahead market. In order to reduce processing time in the presence of large number of virtual bids and offers, PJM only enforces or models a subset of its physical transmission limits in the day-ahead market. Transmission constraints not modeled in the day-ahead market have unlimited transfer capability in the day-ahead market model. The inclusion of the actual, lower transmission capability in the real-time market requires the use of more high cost generation and the use of less low cost generation to serve load, which means a decrease in congestion.[21] The reduction in real-time congestion compared to day-ahead congestion creates negative balancing congestion.

As a day-ahead spread bid, UTCs can take advantage of and profit from LMP differences caused by modeling differences between the day-ahead and real-time market. UTCs clear between source and sink points with little or no price difference in the day-ahead market, and settle the resulting deviations at higher real-time price differences in the real-time market. The result is negative balancing congestion caused by and paid to UTCs in the form of CLMP credits. This is an example of false arbitrage because the UTCs cannot cause prices to converge and the profits to decrease. As a result of the FERC order requiring load to pay balancing congestion, load is responsible for paying the balancing congestion caused by UTCs.[22]

Table 11-16 provides an example of how UTCs can profit from differences in day-ahead and real-time models and generate negative balancing congestion. In the example, Bus A and Bus B are linked by a transmission line. In the day-ahead market the transmission limit is modeled as 9,999 MW (no limit is enforced in the day-ahead market solution). In the real-time market the physical limit between bus A and bus B is 50 MW. Generation at A has a price of $1.00 and Generation at B has a price of $6. There is 100 MW of load at bus A and 100 MW of load at bus B. There is a UTC of 200 MW that will source at bus A and sink at bus B if the spread in the prices between A and B is less than $1.

As a result of the fact that the transmission capability between A and B is unlimited in the day-ahead market, all of load at A and B can be met with the $1 generation at bus A. The constraint between A and B does not bind in

21 Although it seems counter intuitive, as the amount of low cost generation decreases and the amount of high cost generation increases, the difference between load payments to generation and the payments received by generators goes down. High cost generation receives what load pays.

22 On September 15, 2016, FERC ordered PJM to allocate balancing congestion to load, rather than to FTRs, to modify PJM's Stage 1A ARR allocation process and to continue to use portfolio netting. 153 FERC ¶ 61,180 (2016).

day-ahead so the price at A and B is $1. The price spread between bus A and bus B is zero, which is less than the UTC spread requirement of $1, so the UTC clears. The UTC causes a 200 MW injection at A and 200 MW withdrawal at B, creating 200 MW of flow between bus A and bus B. The 300 MW of combined flow from generation at A and UTC injections at A to the load and UTC sink at B does not exceed the DA modeled limit between A and B. This means that all 200 MW of the UTC injection at A and 200 MW of withdrawal at B can clear without forcing a price spread between A and B. Total day-ahead congestion, which is the difference between CLMP charges and credits, is zero. There is no price difference between the two nodes and every MW of injection and every MW of withdrawal at bus A and bus B settles at the same price.

In the real-time market, the transmission line between bus A and bus B has a 50 MW limit. The UTC does not physically exist in the real-time market and therefore has deviations at Bus A (-200 MW) and at Bus B (+200 MW). The UTC must buy at bus A at the real-time price and sell at bus B at the real-time price to settle its deviations. The load at A (100 MW) and B (100 MW) does not change, so there are no load deviations. With only 50 MW of transmission capability between A and B, the generation at A cannot be used to meet total load on the system. Generation from A meets the load at A (100 MW) and can supply only 50 MW of the 100 MW of load at B. Due to the binding constraint between A and B, the remaining 50 MW of load at B must be met with local generation at B at a cost of $6 and the price at A remains $1.

The UTC must buy 200 MW at A at the real-time price of $1 and sell 200 MW at B at the real-time price of $6. The UTC pays $200 at A and is paid $1,200 at B. The result is a net payment to the UTC of $1,000 in balancing credits.

Table 11-15 shows the balancing credits and charges associated with the real-time deviations in the example. Total congestion (day-ahead plus balancing congestion) in this example is negative $1,250. Total CLMP credits (payments) to generation and the UTC exceed the total charges collected from load. The negative balancing congestion that results is paid by the load under the FERC order.[23]

23 153 FERC ¶ 61,180 (2016).

The UTC did not and could not contribute to price convergence between the day-ahead and real-time market and did not and could not improve efficiency in system dispatch or commitment. The UTC took advantage of the modeling differences between the day-ahead and real-time markets. The UTC did significantly increase payments by load. Load was required to pay the UTC $1,000 in negative balancing, over and above the costs of generation that was needed to meet real-time load. The differences in modeling would have resulted in only $250 in negative balancing congestion if there had been no UTCs.

Table 11-15 Example of UTC causing and profiting from negative balancing congestion

Prices	Bus A	Transfer Capability (Line Limit MW)	Bus B	
LMP DA	$1.00	9,999	$1.00	
LMP RT	$1.00	50	$6.00	
Day-Ahead MW	**Bus A**		**Bus B**	**Total MW**
Day-Ahead Generation	200		0	200
Day-Ahead Load	(100)		(100)	(200)
Day-Ahead UTC (+/-)	200		(200)	0
Total MW	300		(300)	0
Day-Ahead Credits and Charges	**Bus A**		**Bus B**	**Total Day-Ahead Congestion**
Total DA Gen Credits	$200.00		$0.00	
Total DA Load Charges	$100.00		$100.00	
Total DA UTC Credits	$200.00		($200.00)	
Total DA Credits	$300.00		($300.00)	$0.00
Total Day-Ahead Congestion (Charges - Credits)				$0.00
Balancing Deviation MW	**Bus A**		**Bus B**	**Total Deviations**
RT GEN Deviations	(50)		50	
RT Load Deviations	0		0	
DA UTC (+/-)	(200)		200	
Total Deviations	(250)		250	0
Balancing Credits and Charges	**Bus A**		**Bus B**	**Balancing Congestion Credits**
Total BA Gen Credits	($50.00)		$300.00	$250.00
Total BA Load Charges	$0.00		$0.00	
Total BA UTC Credits	($200.00)		$1,200.00	$1,000.00
Total BA Credits	($250.00)		$1,500.00	$1,250.00
Total Balancing Congestion (Charges - Credits)				($1,250.00)

Zonal and Load Aggregate Congestion

Zonal, and load aggregate, congestion is calculated on a constraint specific basis for a specific location or set of load pricing nodes (a zone or an aggregate). Local congestion is the difference between what load pays for energy and what generation is paid for energy due to individual binding transmission constraints. Local congestion includes all energy charges or credits incurred to serve a specific load, zone or load aggregate. Local congestion calculations account for the total difference between what the specified load pays and what the generation that serves that load is paid, regardless of whether the zone is a net importer or a net exporter of generation.

Local congestion is calculated on a constraint specific basis. Congestion is the total congestion payments by load at the buses within a defined area minus total CLMP credits received by generation that supplied that load, given the transmission constraints. Congestion reflects the underlying characteristics of the entire power system as it affects the defined area, including the nature and capability of transmission facilities, the offers and geographic distribution of generation facilities, the level and geographic distribution of decremental bids and incremental offers and the geographic and temporal distribution of load.

On a system wide basis, congestion results from transmission constraints that prevent the lowest cost generation from serving some load that must be served by higher cost generation.

The total congestion caused by a constraint is equal to the product of the constraint shadow price times the net flow on the binding constraint. Total congestion caused by the constraint can also be calculated using the CLMPs caused by the constraint at every bus and the net MW injections or MW withdrawals at every affected bus. Congestion associated with a specific constraint is equal to load CLMP charges (CLMP of that specific constraint at each bus times load MW at each bus) caused by that constraint in excess of generation CLMP credits (CLMP of that specific constraint at each bus times generation MW at each bus) caused by that constraint.

Constraint specific CLMPs are determined relative to a reference bus, where there is no congestion and no losses. For purposes of calculating the congestion from an individual constraint, the reference bus for each constraint calculation is the point that is just upstream of the constraint (the bus with the greatest negative price effect from the constraint), allowing any positive price effects of the constraint to be reflected as a positive CLMP.

In order to define the load that is actually paying congestion, congestion is appropriately assigned to downstream (positive CLMP) load buses that paid the congestion caused by the constraint, in proportion to the CLMP charges collected from that load due to that constraint. The congestion collected from each load bus due to a constraint is equal to the CLMP caused by that constraint times the MW of load at that load bus. This calculation is done for both day-ahead congestion and balancing congestion.

Table 11-16 shows day-ahead and balancing congestion by zone and the proportion of congestion resulting from constraints that are external to or internal to each zone, for the first three months of 2023. Constraints are internal to a zone if both the source and sink points of the constraint are in the zone. AEP had the largest zonal congestion costs among all control zones in the first three months of 2023. AEP had $27.8 million in zonal congestion costs, comprised of $35.3 million in zonal day-ahead congestion costs and -$7.5 million in zonal balancing congestion costs. The Nottingham Series Reactor, the Beaumeade Circuit Breaker, the AP South Interface , the East Lima - Haviland Line and the Pipe Creek - Mullin Fisher Body Tap Line contributed $8.6 million, or 31.0 percent of the AEP zonal congestion costs.[24]

Table 11-17 shows the congestion costs by zone for the first three months of 2022.

24 For additional information about the top 20 constraints that affected each zone, see the *2023 Q1 State of the Market Report for PJM*, Appendix F: Congestion and Marginal Losses.

Table 11-16 CLMP credits and charges and total congestion revenue collected by zone (Dollars (Millions)): January through March, 2023

	CLMP Credits and Charges (Millions)										
	Day-Ahead				Balancing				Congestion Costs		
Control Zone	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Internal to Zone	External to Zone	Grand Total
ACEC	$0.7	($1.5)	$0.1	$2.3	$0.0	$0.0	($0.4)	($0.5)	$0.2	$1.7	$1.8
AEP	$5.3	($26.1)	$3.9	$35.3	$0.7	$1.0	($7.2)	($7.5)	$7.6	$20.1	$27.8
APS	$4.6	($10.5)	$1.0	$16.2	$0.2	$0.4	($3.1)	($3.3)	$1.6	$11.3	$12.9
ATSI	$2.8	($14.0)	$1.8	$18.6	$0.3	$0.5	($3.7)	($3.9)	$1.3	$13.5	$14.7
BGE	$2.1	($5.9)	$0.7	$8.7	$0.2	$0.3	($1.6)	($1.7)	$0.4	$6.6	$7.0
COMED	$0.5	($20.9)	$2.7	$24.1	$0.6	$0.9	($5.3)	($5.5)	$1.8	$16.8	$18.6
DAY	$0.0	($4.0)	$0.5	$4.5	$0.1	$0.1	($1.0)	($1.0)	$0.0	$3.5	$3.5
DOM	$9.5	($20.2)	$3.2	$32.9	$0.5	$1.5	($7.5)	($8.5)	($1.1)	$25.5	$24.4
DPL	$5.8	($3.1)	$0.4	$9.3	($0.4)	$0.2	($0.9)	($1.4)	$4.5	$3.4	$7.9
DUKE	$1.1	($4.1)	$0.7	$5.9	$0.1	$0.2	($1.4)	($1.5)	$0.2	$4.2	$4.4
DUQ	$1.1	($1.3)	$0.2	$2.5	$0.1	$0.1	($0.7)	($0.8)	$0.0	$1.8	$1.8
EKPC	$0.6	($2.5)	$0.4	$3.4	$0.1	$0.1	($0.8)	($0.8)	$0.0	$2.6	$2.6
EXT	$0.9	($2.3)	$0.5	$3.6	$0.2	$0.2	($2.0)	($2.0)	$0.5	$1.1	$1.6
JCPLC	$4.3	($4.3)	$0.4	$8.9	$0.1	$0.1	($1.4)	($1.4)	$2.7	$4.8	$7.5
MEC	$1.1	($2.8)	$0.2	$4.1	$0.1	$0.1	($0.8)	($0.9)	$0.6	$2.7	$3.2
OVEC	$0.1	($0.2)	$0.2	$0.4	$0.0	$0.0	($0.1)	($0.1)	$0.1	$0.2	$0.3
PE	$1.7	($3.0)	$0.3	$5.1	$0.1	$0.1	($1.0)	($1.1)	$0.2	$3.8	$4.0
PECO	$2.2	($6.6)	$0.5	$9.3	$0.1	$0.2	($2.0)	($2.1)	$1.4	$5.9	$7.2
PEPCO	$2.1	($4.5)	$0.6	$7.2	$0.2	$0.2	($1.4)	($1.5)	$0.1	$5.7	$5.7
PPL	$3.9	($7.2)	$1.2	$12.2	($0.4)	$0.4	($2.3)	($3.1)	$0.6	$8.5	$9.1
PSEG	$2.8	($6.7)	$0.6	$10.2	$0.1	$0.2	($2.1)	($2.2)	$0.8	$7.2	$8.0
REC	$0.6	($0.2)	$0.6	$1.3	$0.0	$0.0	($0.1)	($0.1)	$1.0	$0.3	$1.3
Total	$53.7	($151.9)	$20.6	$226.2	$2.9	$7.0	($46.7)	($50.8)	$24.5	$151.0	$175.5

Table 11-17 CLMP credits and charges and total congestion revenue collected by zone (Dollars (Millions)): January through March, 2022

	CLMP Credits and Charges (Millions)										
	Day-Ahead				Balancing				Congestion Costs		
Control Zone	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Internal to Zone	External to Zone	Grand Total
ACEC	$1.9	($5.4)	$0.3	$7.5	($0.5)	$1.0	($0.7)	($2.2)	$0.0	$5.3	$5.4
AEP	$22.7	($59.3)	$4.0	$86.0	($3.9)	$11.1	($9.0)	($24.1)	$7.9	$53.9	$61.9
APS	$18.7	($41.7)	$2.3	$62.8	($2.5)	$6.2	($5.1)	($13.8)	$6.0	$42.9	$48.9
ATSI	$12.0	($30.8)	$1.9	$44.7	($1.9)	$5.2	($4.4)	($11.6)	$1.1	$32.1	$33.1
BGE	$5.3	($19.0)	$1.1	$25.5	($1.1)	$3.2	($2.5)	($6.8)	$0.3	$18.4	$18.7
COMED	$10.5	($37.3)	$2.3	$50.1	($2.7)	$7.5	($5.7)	($15.9)	$4.2	$29.9	$34.1
DAY	$1.7	($6.9)	$0.4	$9.1	($0.5)	$1.4	($1.2)	($3.1)	$0.0	$6.0	$6.0
DOM	$160.6	$16.5	$7.7	$151.8	($19.2)	$14.0	($12.6)	($45.9)	$44.9	$61.1	$105.9
DPL	$8.2	($14.6)	$0.8	$23.6	($1.8)	$2.1	($1.7)	($5.6)	$5.8	$12.1	$17.9
DUKE	$2.5	($10.0)	$0.6	$13.1	($0.8)	$2.2	($1.7)	($4.7)	$0.2	$8.1	$8.4
DUQ	$1.9	($4.2)	$0.2	$6.3	($0.4)	$1.0	($0.8)	($2.2)	$0.0	$4.0	$4.0
EKPC	$1.7	($6.5)	$0.3	$8.5	($0.5)	$1.3	($1.0)	($2.8)	$0.0	$5.7	$5.7
EXT	$2.9	($5.6)	$0.6	$9.1	($0.9)	$2.0	($1.7)	($4.6)	$0.5	$4.0	$4.5
JCPLC	$5.6	($13.9)	$0.7	$20.2	($1.2)	$2.4	($1.9)	($5.5)	$0.0	$14.6	$14.7
MEC	$4.2	($10.0)	$0.5	$14.8	($0.6)	$1.5	($1.2)	($3.3)	$0.4	$11.1	$11.5
OVEC	$0.1	($0.4)	$0.1	$0.7	($0.0)	$0.1	($0.1)	($0.2)	$0.1	$0.4	$0.4
PE	$5.9	($13.3)	$0.9	$20.1	($0.7)	$1.7	($1.4)	($3.8)	$3.6	$12.7	$16.3
PECO	$8.2	($24.4)	$1.3	$33.9	($2.0)	$4.1	($3.2)	($9.2)	$0.8	$24.0	$24.7
PEPCO	$5.0	($17.2)	$1.1	$23.2	($1.0)	$3.0	($2.3)	($6.2)	$0.2	$16.8	$17.0
PPL	$12.3	($31.2)	$2.9	$46.4	($1.7)	$4.0	($3.3)	($9.0)	$12.1	$25.3	$37.4
PSEG	$11.8	($28.5)	$1.6	$41.9	($2.4)	$4.3	($3.5)	($10.2)	$5.2	$26.6	$31.8
REC	$0.8	($0.9)	$0.6	$2.3	($0.1)	$0.1	($0.1)	($0.3)	$0.9	$1.0	$1.9
Total	$304.6	($364.6)	$32.2	$701.4	($46.4)	$79.6	($65.1)	($191.2)	$94.2	$416.0	$510.3

In cases where PJM has used an artificial constraint that causes net negative congestion and/or there is no load bus on the constrained side of a binding constraint, the congestion of the artificial constraint is handled as a special case. In the first three months of 2023, the total congestion costs associated with these special cases were $3.4 million or 1.9 percent of the total congestion costs. Table 11-16 and Table 11-17 include congestion allocations from these special case artificial constraints.

There are five categories of artificial constraint based specific allocation special cases: congestion associated with artificial constraints with no downstream load bus (no load bus); congestion associated with artificial constraints with downstream load buses with zero value CLMPs (zero CLMP); congestion associated with closed loop interfaces (closed loop interfaces); congestion associated with CT price setting logic (CT price setting logic); and congestion associated with nontransmission artificial facility constraints in the day-ahead energy market and/or any unaccounted for difference between PJM billed CLMP charges and calculated congestion costs including rounding errors (unclassified).[25]

25 While CT pricing logic was officially discontinued by PJM on September 1, 2021, PJM continued to use a related logic to force inflexible units to be on the margin in both real time and day ahead. These results have been included in the CT Pricing Logic totals.

Table 11-18 and Table 11-19 show total congestion by type of special case, congestion, and total congestion by zone. Closed loop interfaces and CT pricing logic, and similar artificial constraints employed by PJM to force resources to be marginal, generally result in negative congestion on a constraint specific basis. PJM's use of both the closed loop interfaces and CT Pricing Logic forces the affected resource bus LMP to match the marginal offer of the resource. This causes higher CLMP payments to the affected generation than the CLMP load charges to any affected load, resulting in negative congestion associated with the constraint. None of the closed loop interfaces were binding in the first three months of 2023 or 2022.

Table 11-18 CLMP charges and credits and total congestion collected by zone and special case logic (Dollars (Millions)): January through March, 2023

CLMP Credits and Charges (Millions)																	
	Day-Ahead							Balancing									
Control Zone	Load Bus Zero CLMP	CT Price Setting Logic	Closed Loop Interfaces	No Load Buses	Unclassified	Contribution	Total	Load Bus Zero CLMP	CT Price Setting Logic	Closed Loop Interfaces	No Load Buses	Unclassified	Contribution	Total	Grand Total	Special Cases Total	Percent of Special Cases
ACEC	$0.0	($0.0)	$0.0	$0.0	$0.0	$2.3	$2.3	$0.0	($0.0)	$0.0	($0.0)	$0.0	($0.5)	($0.5)	$1.8	($0.0)	(0.6%)
AEP	$0.0	($0.0)	$0.0	$0.4	$0.0	$35.0	$35.3	$0.0	($0.1)	$0.0	($0.0)	$0.0	($7.4)	($7.5)	$27.8	$0.2	0.7%
APS	$0.0	($0.1)	$0.0	$0.0	$0.0	$16.2	$16.2	$0.0	($0.1)	$0.0	($0.0)	$0.0	($3.2)	($3.3)	$12.9	($0.1)	(1.0%)
ATSI	$0.0	($0.0)	$0.0	$0.3	$0.0	$18.3	$18.6	$0.0	($0.1)	$0.0	($0.0)	$0.0	($3.8)	($3.9)	$14.7	$0.2	1.4%
BGE	$0.0	($0.0)	$0.0	$0.0	$0.0	$8.7	$8.7	$0.0	($0.0)	$0.0	($0.0)	$0.0	($1.6)	($1.7)	$7.0	($0.1)	(1.1%)
COMED	$0.0	($0.0)	$0.0	$0.6	$0.0	$23.5	$24.1	$0.0	($0.1)	$0.0	($0.0)	$0.0	($5.5)	($5.5)	$18.6	$0.5	2.9%
DAY	$0.0	($0.0)	$0.0	$0.0	$0.0	$4.6	$4.5	$0.0	($0.0)	$0.0	($0.0)	$0.0	($1.0)	($1.0)	$3.5	($0.0)	(0.6%)
DOM	$0.0	($0.2)	$0.0	$0.0	$0.0	$33.0	$32.9	$0.0	($0.1)	$0.0	($0.0)	$0.0	($8.3)	($8.5)	$24.4	($0.3)	(1.1%)
DPL	$0.0	($0.0)	$0.0	$0.0	$0.0	$9.3	$9.3	$0.0	($0.0)	$0.0	($0.0)	$0.0	($1.4)	($1.4)	$7.9	($0.0)	(0.3%)
DUKE	$0.0	($0.0)	$0.0	$0.0	$0.0	$5.9	$5.9	$0.0	($0.0)	$0.0	($0.0)	$0.0	($1.5)	($1.5)	$4.4	($0.0)	(0.7%)
DUQ	$0.0	($0.0)	$0.0	$0.0	$0.0	$2.6	$2.5	$0.0	($0.0)	$0.0	($0.0)	$0.0	($0.7)	($0.8)	$1.8	($0.0)	(0.9%)
EKPC	$0.0	($0.0)	$0.0	$0.0	$0.0	$3.4	$3.4	$0.0	($0.0)	$0.0	($0.0)	$0.0	($0.8)	($0.8)	$2.6	($0.0)	(0.7%)
EXT	$0.5	($0.0)	$0.0	$0.0	$0.0	$3.1	$3.6	$0.0	($0.0)	$0.0	($0.0)	$0.0	($2.0)	($2.0)	$1.6	$0.5	29.2%
JCPLC	$2.7	($0.0)	$0.0	$0.0	$0.0	$6.2	$8.9	$0.0	($0.0)	$0.0	($0.0)	$0.0	($1.4)	($1.4)	$7.5	$2.7	35.4%
MEC	$0.0	($0.0)	$0.0	$0.0	$0.0	$4.2	$4.1	$0.0	($0.0)	$0.0	($0.0)	$0.0	($0.9)	($0.9)	$3.2	($0.0)	(0.7%)
OVEC	$0.0	($0.0)	$0.0	$0.1	$0.0	$0.2	$0.4	$0.0	($0.0)	$0.0	($0.0)	$0.0	($0.1)	($0.1)	$0.3	$0.1	43.9%
PE	$0.0	($0.0)	$0.0	$0.0	$0.0	$5.1	$5.1	$0.0	($0.0)	$0.0	($0.0)	$0.0	($1.0)	($1.1)	$4.0	($0.0)	(0.6%)
PECO	$0.0	($0.0)	$0.0	$0.0	$0.0	$9.3	$9.3	$0.0	($0.0)	$0.0	($0.0)	$0.0	($2.0)	($2.1)	$7.2	($0.1)	(0.7%)
PEPCO	$0.0	($0.0)	$0.0	$0.0	$0.0	$7.3	$7.2	$0.0	($0.0)	$0.0	($0.0)	$0.0	($1.5)	($1.5)	$5.7	($0.1)	(1.2%)
PPL	$0.0	($0.0)	$0.0	$0.0	$0.0	$12.2	$12.2	$0.0	($0.0)	$0.0	($0.0)	$0.0	($3.0)	($3.1)	$9.1	($0.1)	(0.6%)
PSEG	$0.0	($0.0)	$0.0	$0.0	$0.0	$10.2	$10.2	$0.0	($0.0)	$0.0	($0.0)	$0.0	($2.2)	($2.2)	$8.0	($0.1)	(0.6%)
REC	$0.0	($0.0)	$0.0	$0.0	$0.0	$1.3	$1.3	$0.0	($0.0)	$0.0	($0.0)	$0.0	($0.1)	($0.1)	$1.3	($0.0)	(0.1%)
Total	$3.2	($0.5)	$0.0	$1.5	$0.0	$222.0	$226.2	$0.0	($0.8)	$0.0	($0.0)	$0.0	($49.9)	($50.8)	$175.5	$3.4	1.9%

Table 11-19 CLMP charges and credits and congestion collected by zone and special case logic (Dollars (Millions)): January through March, 2022

	CLMP Credits and Charges (Millions)																
	Day-Ahead							Balancing									
Control Zone	Load Bus Zero CLMP	CT Price Setting Logic	Closed Loop Interfaces	No Load Buses	Unclassified	Contribution	Total	Load Bus Zero CLMP	CT Price Setting Logic	Closed Loop Interfaces	No Load Buses	Unclassified	Contribution	Total	Grand Total	Special Cases Total	Percent of Special Cases
ACEC	$0.0	($0.0)	$0.0	$0.0	$0.0	$7.5	$7.5	$0.0	($0.0)	$0.0	($0.0)	$0.0	($2.1)	($2.2)	$5.4	($0.0)	(0.2%)
AEP	$0.0	($0.0)	$0.0	$0.1	$0.0	$85.9	$86.0	$0.0	($0.2)	$0.0	($0.0)	$0.0	($23.9)	($24.1)	$61.9	($0.1)	(0.2%)
APS	$0.0	($0.0)	$0.0	$0.0	$0.0	$62.8	$62.8	$0.0	($0.1)	$0.0	($0.0)	$0.0	($13.7)	($13.8)	$48.9	($0.1)	(0.2%)
ATSI	$0.0	($0.0)	$0.0	$0.2	$0.0	$44.5	$44.7	$0.0	($0.1)	$0.0	($0.0)	$0.0	($11.5)	($11.6)	$33.1	$0.1	0.3%
BGE	$0.0	($0.0)	$0.0	$0.0	$0.0	$25.5	$25.5	$0.0	($0.0)	$0.0	($0.0)	$0.0	($6.8)	($6.8)	$18.7	($0.0)	(0.2%)
COMED	$0.0	($0.0)	$0.0	$0.7	$0.0	$49.3	$50.1	$0.0	($0.2)	$0.0	($0.0)	$0.0	($15.8)	($15.9)	$34.1	$0.6	1.7%
DAY	$0.0	($0.0)	$0.0	$0.0	$0.0	$9.1	$9.1	$0.0	($0.0)	$0.0	($0.0)	$0.0	($3.1)	($3.1)	$6.0	($0.0)	(0.4%)
DOM	$0.0	($0.0)	$0.0	$0.3	$0.0	$151.5	$151.8	$0.0	($0.2)	$0.0	($0.0)	$0.0	($45.7)	($45.9)	$105.9	$0.1	0.1%
DPL	$0.0	($0.0)	$0.0	$0.0	$0.0	$23.5	$23.6	$0.0	($0.0)	$0.0	($0.0)	$0.0	($5.6)	($5.6)	$17.9	($0.0)	(0.1%)
DUKE	$0.0	($0.0)	$0.0	$0.0	$0.0	$13.1	$13.1	$0.0	($0.0)	$0.0	($0.0)	$0.0	($4.6)	($4.7)	$8.4	($0.0)	(0.4%)
DUQ	$0.0	($0.0)	$0.0	$0.0	$0.0	$6.3	$6.3	$0.0	($0.0)	$0.0	($0.0)	$0.0	($2.2)	($2.2)	$4.0	($0.0)	(0.4%)
EKPC	$0.0	($0.0)	$0.0	$0.0	$0.0	$8.5	$8.5	$0.0	($0.0)	$0.0	($0.0)	$0.0	($2.8)	($2.8)	$5.7	($0.0)	(0.4%)
EXT	$0.4	($0.0)	$0.0	$0.1	$0.0	$8.6	$9.1	$0.0	($0.1)	$0.0	($0.0)	$0.0	($4.6)	($4.6)	$4.5	$0.4	9.1%
JCPLC	$0.0	($0.0)	$0.0	$0.0	$0.0	$20.2	$20.2	$0.0	($0.0)	$0.0	($0.0)	$0.0	($5.5)	($5.5)	$14.7	($0.0)	(0.1%)
MEC	$0.0	($0.0)	$0.0	$0.0	$0.0	$14.8	$14.8	$0.0	($0.0)	$0.0	($0.0)	$0.0	($3.3)	($3.3)	$11.5	($0.0)	(0.2%)
OVEC	$0.0	($0.0)	$0.0	$0.1	$0.0	$0.6	$0.7	$0.0	($0.0)	$0.0	($0.0)	$0.0	($0.2)	($0.2)	$0.4	$0.1	17.1%
PE	$0.0	($0.0)	$0.0	$0.0	$0.0	$20.1	$20.1	$0.0	($0.0)	$0.0	($0.0)	$0.0	($3.7)	($3.8)	$16.3	($0.0)	(0.2%)
PECO	$0.0	($0.0)	$0.0	$0.0	$0.0	$33.9	$33.9	$0.0	($0.1)	$0.0	($0.0)	$0.0	($9.2)	($9.2)	$24.7	($0.1)	(0.2%)
PEPCO	$0.0	($0.0)	$0.0	$0.0	$0.0	$23.2	$23.2	$0.0	($0.0)	$0.0	($0.0)	$0.0	($6.2)	($6.2)	$17.0	$0.0	0.0%
PPL	$0.0	($0.0)	$0.0	$1.7	$0.0	$44.7	$46.4	$0.0	($0.1)	$0.0	($0.0)	($0.0)	($8.9)	($9.0)	$37.4	$1.6	4.4%
PSEG	$0.0	($0.0)	$0.0	$0.0	$0.0	$41.9	$41.9	$0.0	($0.1)	$0.0	($0.0)	$0.0	($10.1)	($10.2)	$31.8	($0.1)	(0.2%)
REC	$0.0	($0.0)	$0.0	$0.0	$0.0	$2.3	$2.3	$0.0	($0.0)	$0.0	($0.0)	$0.0	($0.3)	($0.3)	$1.9	($0.0)	(0.1%)
Total	$0.4	($0.0)	$0.0	$3.2	$0.0	$697.8	$701.4	$0.0	($1.2)	$0.0	($0.0)	$0.0	($190.0)	($191.2)	$510.3	$2.4	0.5%

Fast Start Pricing Effect on Zonal Congestion

PJM implemented fast start pricing in both day-ahead and real-time markets starting September 1, 2021. Table 11-20 compares the congestion costs between the dispatch run and the pricing run in the first three months of 2023. The table shows that the implementation of fast starting pricing logic caused day-ahead total congestion costs to increase $0.1 million (or 0.0 percent), caused negative balancing congestion costs to increase $5.4 million (or 11.9 percent), and caused total congestion costs to decrease $5.3 million (or 2.9 percent) from the dispatch run to the pricing run in the first three months of 2023. In comparing the two pricing results, the same MW, from the dispatch run in the day-ahead market and metered output in the real-time market, are used in the accounting cost calculations.

Table 11-20 Total congestion by dispatch and pricing run (Dollars (Millions)) January through March, 2023

	Congestion Costs (Millions)								
	Dispatch Run			Pricing Run			Difference		
Control Zone	Day-Ahead	Balancing	Total	Day-Ahead	Balancing	Total	Day-Ahead	Balancing	Total
ACEC	$2.4	($0.4)	$2.0	$2.3	($0.5)	$1.8	($0.1)	($0.0)	($0.1)
AEP	$34.4	($6.8)	$27.7	$35.3	($7.5)	$27.8	$0.9	($0.8)	$0.1
APS	$16.7	($3.0)	$13.8	$16.2	($3.3)	$12.9	($0.6)	($0.3)	($0.9)
ATSI	$18.2	($3.5)	$14.7	$18.6	($3.9)	$14.7	$0.5	($0.4)	$0.0
BGE	$9.1	($1.5)	$7.6	$8.7	($1.7)	$7.0	($0.4)	($0.2)	($0.6)
COMED	$24.1	($4.9)	$19.2	$24.1	($5.5)	$18.6	($0.0)	($0.6)	($0.6)
DAY	$4.5	($0.9)	$3.6	$4.5	($1.0)	$3.5	$0.1	($0.1)	($0.0)
DOM	$34.2	($7.4)	$26.7	$32.9	($8.5)	$24.4	($1.3)	($1.0)	($2.3)
DPL	$9.3	($1.2)	$8.1	$9.3	($1.4)	$7.9	($0.0)	($0.2)	($0.2)
DUKE	$6.0	($1.4)	$4.6	$5.9	($1.5)	$4.4	($0.1)	($0.2)	($0.2)
DUQ	$2.7	($0.7)	$2.0	$2.5	($0.8)	$1.8	($0.2)	($0.1)	($0.2)
EKPC	$3.6	($0.7)	$2.9	$3.4	($0.8)	$2.6	($0.2)	($0.1)	($0.2)
EXT	$3.5	($1.8)	$1.8	$3.6	($2.0)	$1.6	$0.1	($0.2)	($0.1)
JCPLC	$6.2	($1.3)	$4.9	$8.9	($1.4)	$7.5	$2.7	($0.1)	$2.6
MEC	$4.3	($0.8)	$3.5	$4.1	($0.9)	$3.2	($0.1)	($0.1)	($0.2)
OVEC	$0.1	($0.1)	$0.1	$0.4	($0.1)	$0.3	$0.3	($0.0)	$0.3
PE	$5.2	($1.0)	$4.2	$5.1	($1.1)	$4.0	($0.1)	($0.1)	($0.2)
PECO	$9.7	($1.9)	$7.8	$9.3	($2.1)	$7.2	($0.4)	($0.2)	($0.6)
PEPCO	$7.6	($1.4)	$6.3	$7.2	($1.5)	$5.7	($0.4)	($0.1)	($0.6)
PPL	$12.5	($2.8)	$9.7	$12.2	($3.1)	$9.1	($0.3)	($0.2)	($0.6)
PSEG	$10.5	($2.0)	$8.5	$10.2	($2.2)	$8.0	($0.4)	($0.2)	($0.6)
REC	$1.3	($0.1)	$1.3	$1.3	($0.1)	$1.3	($0.0)	($0.0)	($0.0)
Total	$226.2	($45.4)	$180.8	$226.2	($50.8)	$175.5	$0.1	($5.4)	($5.3)

Monthly Congestion

Table 11-21 shows day-ahead, balancing and inadvertent congestion costs by month for January 2022 through March 2023. Total congestion costs were lower in the first three months of 2023 than in the first three months of 2022 due to cold weather in January of 2022 and mild weather in the first three months of 2023.

Total negative balancing congestion costs in the first three months of 2023 were highest in March. The top constraint that contributed to the total balancing congestion costs in the first three months of 2023 were the Beaumeade Circuit Breaker. The constraint accounted for 45.8 percent of the total balancing congestion costs in the first three months of 2023. The majority (99.3 percent) of negative balancing congestion costs for the Beaumeade Circuit Breaker were the result of UTC net credits.

In the first three months of 2023 total congestion costs were highest in February and lowest in March.

Table 11-21 Monthly congestion costs by market (Dollars (Millions)): January 2022 through March 2023

	Congestion Costs (Millions)							
	2022				2023			
	Day-Ahead	Balancing	Inadvertent Charges	Total	Day-Ahead	Balancing	Inadvertent Charges	Total
Jan	$443.2	($123.8)	$0.0	$319.4	$69.3	($7.0)	($0.0)	$62.2
Feb	$158.9	($42.6)	$0.0	$116.3	$102.8	($16.4)	$0.0	$86.4
Mar	$99.3	($24.7)	$0.0	$74.5	$54.2	($27.3)	$0.0	$26.8
Apr	$145.9	($31.3)	($0.0)	$114.6				
May	$406.4	($52.2)	($0.0)	$354.2				
Jun	$202.0	($37.6)	$0.0	$164.4				
Jul	$223.6	($33.1)	$0.0	$190.5				
Aug	$355.6	($46.1)	($0.0)	$309.5				
Sep	$248.5	($28.7)	($0.0)	$219.8				
Oct	$161.4	($16.7)	($0.0)	$144.8				
Nov	$215.3	($28.4)	($0.0)	$186.9				
Dec	$365.0	($58.6)	$0.0	$306.4				
Total	$3,025.2	($523.9)	($0.0)	$2,501.3	$226.2	($50.8)	$0.0	$175.5

Figure 11-3 shows PJM monthly total congestion cost for January 2008 through March 2023.

Figure 11-3 Monthly total congestion cost (Dollars (Millions)): January 2008 through March 2023

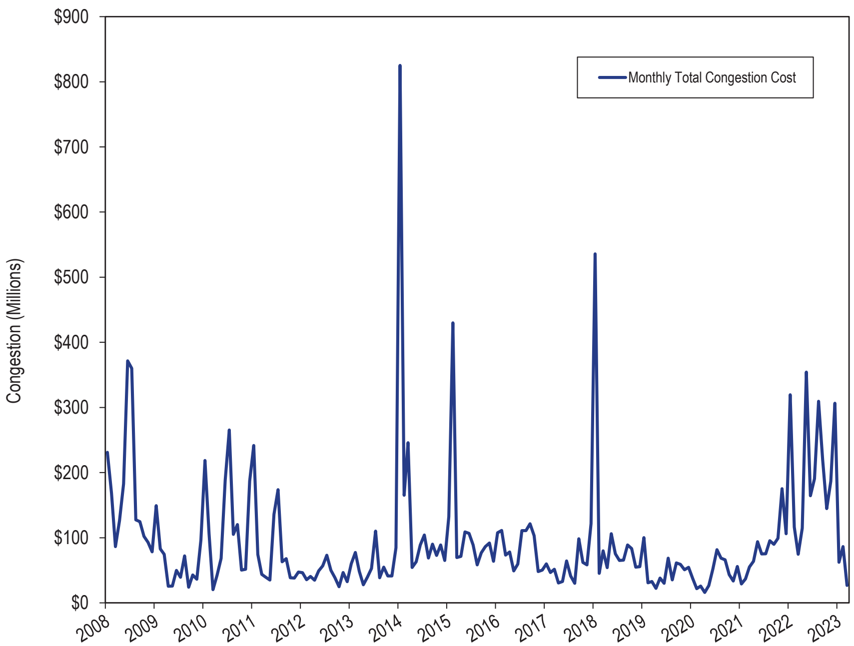


Table 11-22 shows monthly total CLMP credits and charges for each virtual transaction type for January 2022 through March 2023. Virtual transaction CLMP charges, when positive, are the total CLMP charges to the virtual transactions and when negative, are the total CLMP credits to the virtual transactions. The negative totals in Table 11-22 show that virtuals were paid, in net, CLMP credits in the first three months of 2023 and 2022. In the first three months of 2023, 103.1 percent of the total credits to virtuals went to UTCs, compared to 37.1 percent in the first three months of 2022. In the first three months of 2023, the average hourly cleared UTC MW increased by 135.2 percent, compared to the first three months of 2022.

Table 11-22 Monthly CLMP charges by virtual transaction type (Dollars (Millions)): January 2022 through March 2023

		CLMP Credits and Charges (Millions)									
		DEC			INC			Up to Congestion			
Year		Day-Ahead	Balancing	Total	Day-Ahead	Balancing	Total	Day-Ahead	Balancing	Total	Grand Total
2022	Jan	$27.5	($45.7)	($18.3)	$4.4	($22.0)	($17.6)	$10.5	($38.3)	($27.8)	($63.7)
	Feb	$5.9	($20.9)	($15.1)	$5.4	($7.1)	($1.6)	$12.4	($17.6)	($5.1)	($21.8)
	Mar	($0.9)	($3.1)	($4.0)	$7.3	($9.5)	($2.2)	$9.7	($11.3)	($1.6)	($7.7)
	Apr	($3.0)	$3.1	$0.1	$12.5	($19.4)	($6.9)	$10.1	($22.4)	($12.3)	($19.1)
	May	($9.0)	$15.0	$6.0	$19.5	($28.8)	($9.2)	$14.9	($27.6)	($12.6)	($15.8)
	Jun	$1.8	($4.0)	($2.2)	$4.5	($8.3)	($3.8)	$10.5	($25.5)	($15.0)	($21.0)
	Jul	$2.0	($6.8)	($4.8)	$4.2	($6.5)	($2.3)	$12.1	($23.5)	($11.4)	($18.5)
	Aug	$1.8	$1.0	$2.7	$6.7	($17.7)	($10.9)	$16.3	($34.9)	($18.6)	($26.8)
	Sep	($0.6)	($1.0)	($1.6)	$6.2	($8.3)	($2.0)	$11.4	($19.3)	($7.9)	($11.6)
	Oct	($3.6)	$1.5	($2.1)	$7.8	($10.1)	($2.4)	$2.9	($12.0)	($9.2)	($13.6)
	Nov	($5.4)	$6.3	$0.9	$10.9	($15.1)	($4.2)	$11.6	($27.8)	($16.2)	($19.5)
	Dec	($1.3)	($12.2)	($13.5)	$12.0	($17.6)	($5.6)	$21.8	($97.2)	($75.3)	($94.5)
	Total	$15.1	($66.9)	($51.8)	$101.6	($170.3)	($68.7)	$144.1	($357.3)	($213.2)	($333.7)
2023	Jan	($1.9)	$0.3	($1.6)	$2.3	($1.7)	$0.6	$6.4	($6.6)	($0.2)	($1.1)
	Feb	$5.6	($3.1)	$2.5	$3.8	($3.5)	$0.3	$5.5	($11.7)	($6.1)	($3.4)
	Mar	($2.9)	$2.2	($0.7)	$4.4	($5.2)	($0.8)	$8.6	($27.9)	($19.3)	($20.8)
	Total	$0.8	($0.6)	$0.2	$10.5	($10.4)	$0.1	$20.6	($46.2)	($25.6)	($25.3)

Congested Facilities

A congestion event exists when a unit or units must be dispatched out of merit order to control for the potential impact of a contingency on a monitored facility or to control an actual overload. A congestion event hour exists when a specific facility is constrained for one or more five-minute intervals within an hour. A congestion event hour differs from a constrained hour, which is any hour during which one or more facilities are congested. If two facilities are constrained during an hour the result is one constrained hour and two congestion event hours. Constraints are often simultaneous, so the number of congestion event hours usually exceeds the number of constrained hours and the number of congestion event hours usually exceeds the number of hours in a year.

In order to have a consistent metric for real-time and day-ahead congestion frequency, real-time congestion frequency is measured using the convention that an hour is constrained if any of its component five-minute intervals is constrained. This is consistent with the way in which PJM reports real-time congestion.

In the first three months of 2023, there were 18,602 day-ahead, congestion event hours compared to 21,091 day-ahead congestion event hours in the first three months of 2022. Of the day-ahead congestion event hours in the first three months of 2023, only 2,171 (11.7 percent) were also constrained in the real-time energy market (Table 11-25). In the first three months of 2023, there were 4,040 real-time, congestion event hours compared to 8,431 real-time, congestion event hours in the first three months of 2022. Of the real-time congestion event hours in the first three months of 2023, 2,181 (54.0 percent) were also constrained in the day-ahead energy market (Table 11-26).

The top five constraints by congestion costs contributed $55.3 million, or 31.5 percent, of the total PJM congestion costs in the first three months of 2023. The top five constraints were the Nottingham Series Reactor, the Beaumeade Circuit Breaker, the AP South Interface, the Gardners - Texas Eastern Line and the Bedington - Black Oak Interface.

Congestion by Facility Type and Voltage

Day-ahead, congestion event hours decreased on all types of facilities except transformers in the first three months of 2023. Congestion event hours on lines decreased by 1,590 congestion event hours from 13,634 day-ahead, congestion event hours in the first three months of 2022 to 12,044 day-ahead congestion event hours in the first three months of 2023 (Table 11-25).

Real-time, congestion event hours decreased on all types of facilities in the first three months of 2023 (Table 11-26). Lines decreased by 2,507 congestion event hours from 4,089 real-time, congestion event hours in the first three months of 2022 to 1,582 real-time congestion event hours in the first three months of 2023.

Day-ahead congestion costs decreased on all types of facilities in the first three months of 2023 compared to the first three months of 2022 (Table 11-23).

Negative balancing congestion costs decreased on all types of facilities except transformers in the first three months of 2023 compared to the first three months of 2022 (Table 11-24). Table 11-23 provides congestion event hour subtotals and congestion cost subtotals comparing the first three months of 2023 results by facility type: line, transformer, interface, flowgate and unclassified facilities.[26] [27]

Table 11-23 Congestion summary (By facility type): January through March, 2023

	CLMP Credits and Charges (Millions)										
	Day-Ahead				Balancing					Event Hours	
Type	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Congestion Costs	Day-Ahead	Real-Time
Flowgate	($12.5)	($37.1)	($0.1)	$24.5	($0.3)	($2.1)	($7.6)	($5.9)	$18.7	2,278	1,335
Interface	$7.7	($25.6)	$0.2	$33.6	$0.2	$0.7	($0.2)	($0.7)	$32.9	237	28
Line	$18.5	($77.9)	$10.8	$107.2	($1.9)	$1.8	($13.5)	($17.2)	$90.0	12,044	1,582
Transformer	$1.6	($5.2)	$2.7	$9.5	($0.5)	$0.7	$0.1	($1.1)	$8.4	2,058	150
Other	$38.3	($6.1)	$6.9	$51.3	$5.5	$5.9	($25.4)	($25.8)	$25.6	1,985	945
Unclassified	$0.0	($0.0)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	NA	NA
Total	$53.7	($151.9)	$20.6	$226.2	$2.9	$7.0	($46.7)	($50.8)	$175.5	18,602	4,040

26 Unclassified are congestion costs related to nontransmission facility constraints in the day-ahead energy market and any unaccounted for difference between PJM billed CLMP charges and calculated congestion costs including rounding errors. Nontransmission facility constraints include day-ahead market only constraints such as constraints on virtual transactions and constraints associated with phase-angle regulators.

27 The term flowgate refers to MISO reciprocal coordinated flowgates and NYISO M2M flowgates.

Table 11-24 Congestion summary (By facility type): January through March, 2022

	CLMP Credits and Charges (Millions)										
	Day-Ahead				Balancing					Event Hours	
Type	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Congestion Costs	Day-Ahead	Real-Time
Flowgate	($25.5)	($127.4)	$5.8	$107.7	($3.4)	$9.1	($15.0)	($27.5)	$80.2	3,946	2,908
Interface	$51.0	($111.3)	$5.1	$167.4	($11.4)	$42.9	($21.2)	($75.4)	$92.0	794	715
Line	$249.4	($112.9)	$18.4	$380.6	($35.1)	$24.7	($27.4)	($87.3)	$293.4	13,634	4,089
Transformer	$7.4	($8.7)	$1.6	$17.6	($0.1)	$0.2	($0.2)	($0.5)	$17.1	1,753	220
Other	$22.3	($4.4)	$1.3	$28.0	$3.6	$2.6	($1.3)	($0.4)	$27.6	964	499
Unclassified	$0.0	$0.0	($0.0)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	NA	NA
Total	$304.6	($364.6)	$32.2	$701.4	($46.4)	$79.6	($65.1)	($191.2)	$510.3	21,091	8,431

virtual bids and offers. Virtual bids and offers also contribute to day-ahead market flows that do not align with realized real-time physical flows. The number of congestion event hours in the day-ahead energy market was about three times the number of congestion event hours in the real-time energy market, despite the fact that only a portion of PJM transmission facilities are modeled in the day-ahead market.

Table 11-25 and Table 11-26 compare day-ahead and real-time congestion event hours. Among the hours for which a facility is constrained in the day-ahead energy market, the number of hours during which the facility is also constrained in the real-time energy market are presented in Table 11-25.[28]

Among the hours for which a facility was constrained in the real-time energy market, the number of hours during which the facility was also constrained in the day-ahead energy market are presented in Table 11-26.

Congestion frequency continued to be significantly higher in the day-ahead energy market than in the real-time energy market in the first three months of 2023. The number of congestion event hours in the day-ahead energy market was about two and half times the number of congestion event hours in the real-time energy market.

In the real-time market, PJM has the ability to model and monitor almost all PJM transmission facilities. In the day-ahead market, PJM can model and monitor only a portion of PJM transmission facilities. This difference in modeling is the basis of false arbitrage and the source of significant virtual profits. While more constraints are modeled and monitored in the PJM real-time market than the day-ahead market, there is significantly more network flow in the day-ahead market than in the real-time market as a result of

28 Constraints are mapped to transmission facilities. In the day-ahead energy market, within a given hour, a single facility may be associated with multiple constraints. In such situations, the same facility accounts for more than one constraint-hour for a given hour in the day-ahead energy market. Similarly in the real-time market a facility may account for more than one constraint-hour within a given hour.

Table 11-25 Congestion event hours (day-ahead against real-time): January through March, 2022 and 2023

	Congestion Event Hours					
	2022 (Jan - Mar)			2023 (Jan - Mar)		
Type	Day-Ahead Constrained	Corresponding Real-Time Constrained	Percent	Day-Ahead Constrained	Corresponding Real-Time Constrained	Percent
Flowgate	3,946	1,263	32.0%	2,278	554	24.3%
Interface	794	210	26.4%	237	15	6.3%
Line	13,634	2,005	14.7%	12,044	650	5.4%
Transformer	1,753	57	3.3%	2,058	117	5.7%
Other	964	369	38.3%	1,985	835	42.1%
Total	21,091	3,904	18.5%	18,602	2,171	11.7%

Table 11-26 Congestion event hours (real-time against day-ahead): January through March, 2022 and 2023

	Congestion Event Hours					
	2022 (Jan - Mar)			2023 (Jan - Mar)		
Type	Real-Time Constrained	Corresponding Day-Ahead Constrained	Percent	Real-Time Constrained	Corresponding Day-Ahead Constrained	Percent
Flowgate	2,908	1,272	43.7%	1,335	553	41.4%
Interface	715	243	34.0%	28	18	64.3%
Line	4,089	2,172	53.1%	1,582	655	41.4%
Transformer	220	57	25.9%	150	118	78.7%
Other	499	369	73.9%	945	837	88.6%
Total	8,431	4,113	48.8%	4,040	2,181	54.0%

Table 11-27 shows congestion costs by facility voltage class for the first three months of 2023. Congestion costs in the first three months of 2023 decreased for all facility voltage classes compared to the first three months of 2022.

Table 11-27 Congestion summary (By facility voltage): January through March, 2023

	CLMP Credits and Charges (Millions)										
	Day-Ahead				Balancing					Event Hours	
Voltage (kV)	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Costs	Total	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Costs	Total	Congestion Costs	Day-Ahead	Real-Time
765	($0.0)	($0.0)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	1	0
500	$9.0	($28.0)	$0.9	$37.8	$0.3	$0.8	($0.3)	($0.8)	$37.0	468	38
345	($7.1)	($22.7)	$0.5	$16.0	($0.2)	($0.3)	$0.0	$0.2	$16.2	2,044	383
230	$56.8	($23.2)	$14.7	$94.8	$5.3	$8.0	($37.3)	($40.0)	$54.8	5,999	1,403
161	$0.0	($0.0)	$0.0	$0.0	($0.0)	($0.0)	($0.0)	($0.1)	($0.0)	51	5
138	($4.1)	($56.2)	$3.6	$55.7	($2.3)	($2.3)	($8.4)	($8.4)	$47.3	6,391	1,811
115	($5.0)	($22.4)	$0.7	$18.1	($0.0)	$0.9	($0.8)	($1.7)	$16.4	1,890	377
69	$4.1	$0.6	$0.3	$3.8	($0.1)	($0.0)	$0.1	($0.0)	$3.8	1,758	23
1	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	0	0
Unclassified	$0.0	($0.0)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	NA	NA
Total	$53.7	($151.9)	$20.6	$226.2	$2.9	$7.0	($46.7)	($50.8)	$175.5	18,602	4,040

Table 11-28 Congestion summary (By facility voltage): January through March, 2022

	CLMP Credits and Charges (Millions)										
	Day-Ahead				Balancing					Event Hours	
Voltage (kV)	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Congestion Costs	Day-Ahead	Real-Time
765	$0.1	($0.1)	$0.0	$0.3	$0.0	$0.0	$0.0	$0.0	$0.3	3	0
500	$54.7	($119.6)	$6.1	$180.4	($12.5)	$42.1	($24.4)	($79.1)	$101.3	1,123	831
345	($9.5)	($55.0)	$1.6	$47.1	($1.7)	$0.0	($5.1)	($6.8)	$40.3	1,414	734
230	$66.1	($183.9)	$12.6	$262.6	($11.4)	$15.3	($18.6)	($45.3)	$217.3	7,531	2,177
161	($0.0)	($0.9)	$0.1	$1.0	$0.0	$0.1	($0.1)	($0.3)	$0.8	70	69
138	$37.8	($49.0)	$4.4	$91.2	($4.5)	$6.8	($7.5)	($18.9)	$72.3	6,021	2,846
115	$154.2	$47.8	$6.2	$112.6	($16.4)	$14.8	($9.5)	($40.7)	$71.9	3,392	1,698
69	$1.3	($3.5)	$1.1	$5.9	$0.1	$0.1	($0.1)	($0.2)	$5.7	1,525	60
1	($0.0)	($0.4)	$0.0	$0.4	$0.0	$0.2	$0.2	$0.1	$0.4	12	16
Unclassified	$0.0	$0.0	($0.0)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	NA	NA
Total	$304.6	($364.6)	$32.2	$701.4	($46.4)	$79.6	($65.1)	($191.2)	$510.3	21,091	8,431

Constraint Frequency

Table 11-29 lists the constraints for the first three months of 2022 and 2023 that were most frequently binding and Table 11-30 shows the constraints which experienced the largest change in congestion event hours from the first three months of 2022 to the first three months of 2023. In Table 11-29, constraints are presented in descending order of total day-ahead event hours and real-time event hours for the first three months of 2023. In Table 11-30, the constraints are presented in descending order of absolute value of day-ahead event hour changes plus real-time event hour changes from the first three months of 2022 to the first three months of 2023.

Table 11-29 Top 25 constraints: January through March, 2022 and 2023

			(Jan - Mar)												
			Congestion Event Hours						Percent of Annual Hours						
			Day-Ahead			Real-Time			Day-Ahead			Real-Time			
No.	Constraint	Type	2022	2023	Change	2022	2023	Change	2022	2023	Change	2022	2023	Change	
1	Nottingham	Other	673	1,735	1,062	402	850	448	31.2%	80%	49%	19%	39%	21%	
2	Weedman - Mahomet	Flowgate	0	469	469	0	464	464	0%	22%	22%	0%	21%	21%	
3	Sayreville - Sayreville	Line	7	903	896	0	0	0	0%	42%	42%	0%	0%	0%	
4	Gardners - Texas Eastern	Line	393	626	233	54	138	84	18%	29%	11%	3%	6%	4%	
5	Easton - Emuni	Line	409	750	341	0	0	0	19%	35%	16%	0%	0%	0%	
6	Ramapo (ConEd) - S Mahwah (RECO)	Line	596	729	133	0	0	0	28%	34%	6%	0%	0%	0%	
7	DoeX530	Transformer	66	599	533	0	0	0	3%	28%	25%	0%	0%	0%	
8	Allen - R.P. Mone	Line	151	473	322	92	67	(25)	7%	22%	15%	4%	3%	(1%)	
9	Turkey Hill - Mascoutah	Flowgate	20	281	261	27	236	209	1%	13%	12%	1%	11%	10%	
10	Graceton - Safe Harbor	Line	78	388	310	67	127	60	4%	18%	14%	3%	6%	3%	
11	Monroe - Vineland	Line	29	453	424	0	1	1	1%	21%	20%	0%	0%	0%	
12	Mountain	Transformer	633	426	(207)	0	0	0	29%	20%	(10%)	0%	0%	0%	
13	Garrett - Garrett Tap	Line	210	398	188	0	0	0	10%	18%	9%	0%	0%	0%	
14	Pipe Creek - Mullin Fisher Body Tap	Line	0	372	372	0	0	0	0%	17%	17%	0%	0%	0%	
15	Haumesser Road - Steward	Line	485	256	(229)	182	99	(83)	22%	12%	(11%)	8%	5%	(4%)	
16	East Lima - Haviland	Line	241	265	24	32	77	45	11%	12%	1%	1%	4%	2%	
17	Lenox - North Meshoppen	Line	995	192	(803)	1,041	148	(893)	46%	9%	(37%)	48%	7%	(41%)	
18	Powerton - Towerline	Flowgate	35	324	289	0	0	0	2%	15%	13%	0%	0%	0%	
19	Greentown	Flowgate	0	216	216	0	88	88	0%	10%	10%	0%	4%	4%	
20	Miami Fort	Transformer	5	282	277	0	0	0	0%	13%	13%	0%	0%	0%	
21	Howard - Melmore	Line	0	207	207	0	73	73	0%	10%	10%	0%	3%	3%	
22	Valero - Valero Packing Tap	Line	0	231	231	0	18	18	0%	11%	11%	0%	1%	1%	
23	Harwood	Transformer	0	143	143	0	91	91	0%	7%	7%	0%	4%	4%	
24	Bergen - Hudson	Line	255	233	(22)	0	0	0	12%	11%	(1%)	0%	0%	0%	
25	Cedar Grove Sub - Williams	Line	467	221	(246)	155	11	(144)	22%	10%	(11%)	7%	1%	(7%)	

Table 11-30 Top 25 constraints year to year change in occurrence: January through March, 2022 and 2023

			(Jan - Mar)												
			Congestion Event Hours						Percent of Annual Hours						
			Day-Ahead			Real-Time			Day-Ahead			Real-Time			
No.	Constraint	Type	2022	2023	Change	2022	2023	Change	2022	2023	Change	2022	2023	Change
1	Prest - Tibb	Flowgate	1,017	39	(978)	848	100	(748)	47%	2%	(45%)	39%	5%	(35%)
2	Lenox - North Meshoppen	Line	995	192	(803)	1,041	148	(893)	46%	9%	(37%)	48%	7%	(41%)
3	Nottingham	Other	673	1,735	1,062	402	850	448	31%	80%	49%	19%	39%	21%
4	Greys Point - Harmony Village	Line	763	0	(763)	548	12	(536)	35%	0%	(35%)	25%	1%	(25%)
5	Weedman - Mahomet	Flowgate	0	469	469	0	464	464	0%	22%	22%	0%	21%	21%
6	Northwest Tap - Purdue	Flowgate	494	4	(490)	441	0	(441)	23%	0%	(23%)	20%	0%	(20%)
7	Sayreville - Sayreville	Line	7	903	896	0	0	0	0%	42%	42%	0%	0%	0%
8	Cumberland - Juniata	Line	525	51	(474)	183	0	(183)	24%	2%	(22%)	8%	0%	(8%)
9	Berwick - Koonsville	Line	608	0	(608)	0	0	0	28%	0%	(28%)	0%	0%	0%
10	Lafayette	Flowgate	373	0	(373)	161	0	(161)	17%	0%	(17%)	7%	0%	(7%)
11	DoeX530	Transformer	66	599	533	0	0	0	3%	28%	25%	0%	0%	0%
12	Turkey Hill - Mascoutah	Flowgate	20	281	261	27	236	209	1%	13%	12%	1%	11%	10%
13	Hope Creek - Silver Run	Line	415	1	(414)	53	0	(53)	19%	0%	(19%)	2%	0%	(2%)
14	St John - Green Acres	Flowgate	245	0	(245)	191	0	(191)	11%	0%	(11%)	9%	0%	(9%)
15	Monroe - Vineland	Line	29	453	424	0	1	1	1%	21%	20%	0%	0%	0%
16	Brunswick - Meadow Road	Line	314	11	(303)	105	0	(105)	15%	1%	(14%)	5%	0%	(5%)
17	Nucor - Whitestown	Flowgate	206	3	(203)	192	0	(192)	10%	0%	(9%)	9%	0%	(9%)
18	Cedar Grove Sub - Williams	Line	467	221	(246)	155	11	(144)	22%	10%	(11%)	7%	1%	(7%)
19	Maroa E - Goose Creek	Flowgate	289	10	(279)	104	1	(103)	13%	0%	(13%)	5%	0%	(5%)
20	Cayuga	Flowgate	198	0	(198)	178	0	(178)	9%	0%	(9%)	8%	0%	(8%)
21	Bedington - Black Oak	Interface	187	38	(149)	226	0	(226)	9%	2%	(7%)	10%	0%	(10%)
22	Pipe Creek - Mullin Fisher Body Tap	Line	0	372	372	0	0	0	0%	17%	17%	0%	0%	0%
23	Graceton - Safe Harbor	Line	78	388	310	67	127	60	4%	18%	14%	3%	6%	3%
24	Frackville - Siegfried	Line	356	0	(356)	0	0	0	16%	0%	(16%)	0%	0%	0%
25	Butler - Karns City	Line	350	95	(255)	87	0	(87)	16%	4%	(12%)	4%	0%	(4%)

Top Constraints

Table 11-31 and Table 11-32 show the top constraints contributing to congestion costs by facility for the first three months of 2023 and 2022.

The Nottingham Series Reactor is the largest contributor to positive congestion costs due to frequently binding since October 2021, with $44.1 million in total congestion costs and 25.2 percent of the total PJM congestion costs in the first three months of 2023. The day-ahead congestion event hours of Nottingham Series Reactor increased from 673 in the first three months of 2022 to 1,735 in the first three months of 2023 and the real-time congestion event hours of Nottingham Series Reactor increased from 402 in the first three months of 2022 to 850 in the first three months of 2023 (Table 11-29.) The frequent binding of the Nottingham Series Reactor in both day-ahead and real-time was caused by transmission outages of the equipment located in MEC, PPL and the PE zones.

The Beaumeade Circuit Breaker was the largest contributor to negative total congestion costs in the first three months of 2023, due to large negative balancing congestion costs the first three months of 2023. The Beaumeade Circuit Breaker constraint was binding for nine days in March in the real-time market in the first three months of 2023. Among the nine days, March 23, 2023 counted for 52.7 percent of total negative balancing congestion costs or -$12.2 million. The majority (96.6 percent) of negative balancing congestion costs for the Beaumeade Circuit Breaker were the result of UTCs' net credits.

Table 11-31 Top 25 constraints affecting congestion costs: January through March, 2023[29]

				CLMP Credits and Charges (Millions)									
				Day-Ahead				Balancing					
No.	Constraint	Type	Location	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Congestion Costs	Percent of Total PJM Congestion Costs
1	Nottingham	Other	PECO	$37.3	($2.7)	$5.7	$45.8	$4.6	$3.9	($2.4)	($1.6)	$44.1	25.2%
2	Beaumeade	Other	DOM	$1.5	($0.4)	$0.9	$2.8	$1.9	$2.1	($23.1)	($23.3)	($20.4)	(11.6%)
3	AP South	Interface	500	$4.9	($7.4)	$0.4	$12.6	$0.2	$0.7	($0.2)	($0.7)	$11.9	6.8%
4	Gardners - Texas Eastern	Line	MEC	($5.7)	($17.7)	($0.1)	$11.9	$0.1	$0.3	($0.4)	($0.6)	$11.3	6.5%
5	Bedington - Black Oak	Interface	500	$2.2	($6.1)	$0.1	$8.4	$0.0	$0.0	$0.0	$0.0	$8.4	4.8%
6	Allen - R.P. Mone	Line	AEP	($2.0)	($8.6)	$0.8	$7.4	($0.5)	($0.5)	($0.0)	($0.0)	$7.4	4.2%
7	Weedman - Mahomet	Flowgate	MISO	($2.8)	($9.0)	$0.4	$6.7	($0.1)	($1.2)	($1.9)	($0.8)	$5.9	3.4%
8	Graceton - Safe Harbor	Line	BGE	$4.0	($1.1)	$0.7	$5.9	$0.5	$0.1	($0.4)	($0.0)	$5.9	3.3%
9	East Lima - Haviland	Line	AEP	($8.6)	($12.7)	$0.6	$4.7	($0.0)	($0.4)	($0.2)	$0.2	$4.9	2.8%
10	AEP - DOM	Interface	500	$1.7	($2.9)	$0.3	$4.9	$0.0	$0.0	$0.0	$0.0	$4.9	2.8%
11	Ashburn - Cochran Mill	Line	DOM	$0.6	($0.4)	$0.4	$1.4	$0.5	$0.8	($5.8)	($6.2)	($4.8)	(2.7%)
12	West	Interface	500	($0.8)	($6.0)	($0.5)	$4.7	($0.0)	$0.0	$0.0	($0.0)	$4.7	2.7%
13	Cedar Grove Sub - Williams	Line	PSEG	$1.6	($2.5)	$1.1	$5.2	($0.2)	$0.0	($0.4)	($0.6)	$4.6	2.6%
14	Conastone - Northwest	Line	BGE	$3.1	($1.2)	$0.4	$4.7	$0.1	$0.5	$0.1	($0.3)	$4.4	2.5%
15	Pipe Creek - Mullin Fisher Body Tap	Line	AEP	($3.1)	($5.6)	$1.2	$3.7	$0.0	$0.0	$0.0	$0.0	$3.7	2.1%
16	Charlottesville - Proffit D.P.	Line	DOM	$1.2	($2.2)	($0.2)	$3.2	$0.0	$0.0	$0.0	$0.0	$3.2	1.8%
17	Butler - Karns City	Line	APS	$10.3	$5.1	($2.4)	$2.8	$0.0	$0.0	$0.0	$0.0	$2.8	1.6%
18	Tanners Creek - Dearborn	Flowgate	MISO	($2.0)	($4.6)	$0.2	$2.8	$0.0	$0.0	$0.0	$0.0	$2.8	1.6%
19	Sayreville - Sayreville	Line	JCPLC	$2.7	$0.0	$0.0	$2.7	$0.0	$0.0	$0.0	$0.0	$2.7	1.6%
20	East	Interface	500	($0.2)	($2.8)	$0.0	$2.6	$0.0	$0.0	$0.0	$0.0	$2.6	1.5%
21	Highland - Commerce	Line	ATSI	$0.5	($1.8)	($0.1)	$2.2	$0.0	$0.1	$0.1	$0.0	$2.2	1.3%
22	Chaparral - Carson	Line	DOM	$0.0	($2.1)	$0.0	$2.2	$0.0	$0.0	$0.0	$0.0	$2.2	1.2%
23	Dauphin - Juniata	Line	PPL	($0.7)	($2.7)	$0.1	$2.1	$0.0	$0.0	$0.0	$0.0	$2.1	1.2%
24	Turkey Hill - Mascoutah	Flowgate	MISO	($1.4)	($3.6)	$0.4	$2.6	$0.1	($0.0)	($0.7)	($0.6)	$2.1	1.2%
25	Dickerson - Dickerson Station	Line	PEPCO	$1.1	$0.4	$1.3	$2.0	$0.0	$0.0	$0.0	$0.0	$2.0	1.1%
	Top 25 Total			$45.5	($98.7)	$11.9	$156.1	$7.2	$6.2	($35.4)	($34.4)	$121.7	69.4%
	All Other Constraints			$8.3	($53.1)	$8.7	$70.2	($4.3)	$0.8	($11.3)	($16.4)	$53.8	30.6%
	Total			$53.7	($151.9)	$20.6	$226.2	$2.9	$7.0	($46.7)	($50.8)	$175.5	100.0%

29 All flowgates are mapped to MISO as Location if they are flowgates coordinated by both PJM and MISO regardless of the location of the flowgates.

Table 11-32 Top 25 constraints affecting congestion costs: January through March, 2022[30]

				CLMP Credits and Charges (Millions)									
				Day-Ahead				Balancing					
No.	Constraint	Type	Location	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Congestion Costs	Percent of Total PJM Congestion Costs
1	Cumberland - Juniata	Line	PPL	($2.8)	($49.3)	$1.2	$47.7	$2.0	($0.5)	($1.9)	$0.5	$48.2	9.4%
2	Bedington - Black Oak	Interface	500	$25.2	($43.4)	$1.8	$70.5	($0.8)	$15.1	($7.0)	($23.0)	$47.4	9.3%
3	Greys Point - Harmony Village	Line	DOM	$139.0	$79.5	$3.3	$62.8	($15.8)	$2.2	($3.5)	($21.5)	$41.3	8.1%
4	AP South	Interface	500	$22.0	($27.2)	$1.7	$50.9	($1.5)	$9.9	($3.9)	($15.4)	$35.5	7.0%
5	Frackville - Siegfried	Line	PPL	$9.0	($22.5)	$0.9	$32.4	$0.0	$0.0	$0.0	$0.0	$32.4	6.4%
6	Nottingham	Other	PECO	$22.7	$0.1	$1.0	$23.6	$3.6	$2.4	($1.0)	$0.2	$23.8	4.7%
7	Lenox - North Meshoppen	Line	PE	$7.8	($28.8)	$2.9	$39.6	($0.3)	$12.6	($6.0)	($18.9)	$20.7	4.1%
8	Prest - Tibb	Flowgate	MISO	($4.7)	($26.0)	$2.9	$24.2	$0.2	$1.7	($2.9)	($4.4)	$19.8	3.9%
9	AEP - DOM	Interface	500	$8.3	($14.1)	$1.4	$23.8	($0.6)	$5.1	($3.8)	($9.4)	$14.4	2.8%
10	Northwest Tap - Purdue	Flowgate	MISO	($2.3)	($15.4)	$0.1	$13.2	$0.2	$1.5	$0.0	($1.4)	$11.8	2.3%
11	Hope Creek - Silver Run	Line	PSEG	($0.7)	($12.5)	$0.1	$11.9	($0.4)	$0.8	$0.6	($0.6)	$11.3	2.2%
12	Nucor - Whitestown	Flowgate	MISO	($3.9)	($15.8)	($0.4)	$11.5	($0.1)	$0.0	($0.2)	($0.3)	$11.2	2.2%
13	Dauphin - Juniata	Line	PPL	($3.5)	($14.5)	$0.1	$11.1	$0.0	$0.0	$0.0	$0.0	$11.1	2.2%
14	Cedar Grove Sub - Roseland	Line	PSEG	$6.0	($7.7)	$1.4	$15.0	($2.0)	$1.7	($0.3)	($3.9)	$11.1	2.2%
15	Cedar Grove Sub - Williams	Line	PSEG	$8.1	($10.1)	$2.4	$20.5	($3.5)	$3.2	($4.3)	($11.0)	$9.5	1.9%
16	Butler - Karns City	Line	APS	$32.7	$21.1	($2.5)	$9.1	($1.1)	($0.8)	$0.5	$0.1	$9.2	1.8%
17	Maroa E - Goose Creek	Flowgate	MISO	($2.9)	($12.1)	$0.2	$9.4	($0.1)	($0.3)	($0.5)	($0.4)	$9.0	1.8%
18	Lafayette	Flowgate	MISO	($2.9)	($12.5)	($0.1)	$9.5	($0.1)	$0.5	$0.1	($0.6)	$8.9	1.7%
19	East	Interface	500	($2.1)	($12.7)	$0.3	$10.9	($7.6)	$6.9	($4.6)	($19.1)	($8.2)	(1.6%)
20	Bridgewater - Middlesex	Line	PSEG	$3.4	($4.3)	$0.0	$7.7	($0.2)	$0.9	$0.3	($0.7)	$7.0	1.4%
21	Cedar Grove - Clifton	Line	PSEG	$3.9	($3.0)	$0.4	$7.3	($0.4)	$0.2	($0.2)	($0.8)	$6.4	1.3%
22	Cedar Creek - Silver Run	Line	DPL	($0.7)	($7.3)	$0.1	$6.7	($1.4)	($0.5)	$0.0	($1.0)	$5.7	1.1%
23	Harwood - Susquehanna	Line	PPL	$1.4	($4.3)	$0.2	$5.9	($0.1)	($0.0)	($0.2)	($0.2)	$5.7	1.1%
24	PA Central	Interface	500	$0.0	($0.6)	($0.0)	$0.6	$0.6	$4.8	($1.3)	($5.5)	($4.9)	(1.0%)
25	West	Interface	500	($1.0)	($6.0)	($0.0)	$5.0	($0.5)	($0.0)	$0.2	($0.2)	$4.7	0.9%
	Top 25 Total			$261.9	($249.4)	$19.4	$530.7	($30.1)	$67.4	($40.1)	($137.6)	$393.1	77.0%
	All Other Constraints			$42.8	($115.2)	$12.8	$170.7	($16.4)	$12.2	($25.0)	($53.5)	$117.2	23.0%
	Total			$304.6	($364.6)	$32.2	$701.4	($46.4)	$79.6	($65.1)	($191.2)	$510.3	100.0%

Figure 11-4 shows the hourly total congestion costs of the top five constraints in the first three months of 2023. The Nottingham Series Reactor was the top constraint.

The Beaumeade Circuit Breaker contributed most in total negative congestion costs due to large negative balancing congestion costs between March 17, 2023 and March 27, 2023. The negative balancing congestion costs were significant for two hours on March 23, 2023 and one hour on March 26, 2023. During those three hours, the Beaumeade Circuit Breaker was not binding in the day-ahead market and was binding in the real-time market. In the real-time market, the Beaumeade Circuit Breaker had constraint violations in several intervals in each of the three hours and the transmission penalty factors were set to $2,000.

30 All flowgates are mapped to MISO as Location if they are flowgates coordinated by both PJM and MISO regardless of the location of the flowgates.

Figure 11-4 Top five constraints affecting total congestion costs: January through March, 2023

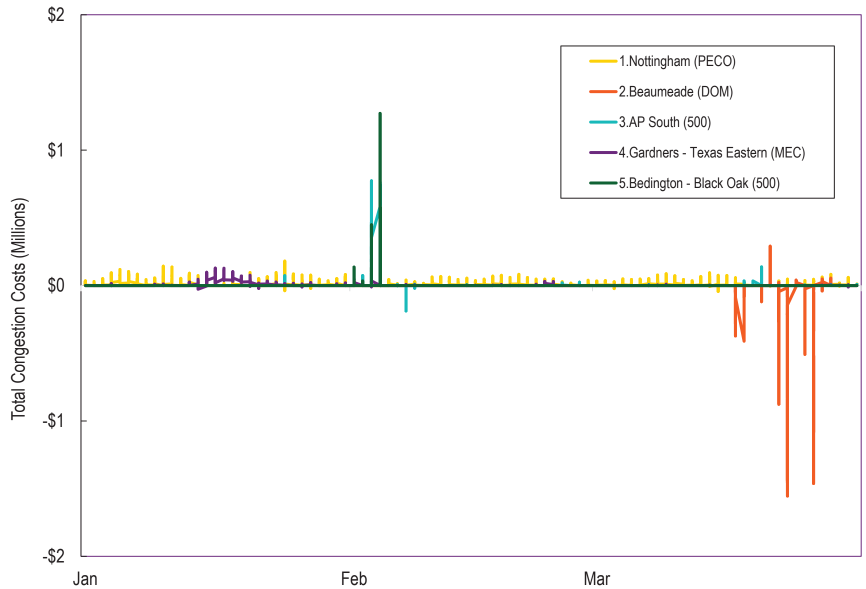


Figure 11-5 shows the locations of the top 10 constraints by total congestion costs on a contour map of the real-time, load-weighted average CLMP in the first three months of 2023.

Figure 11-5 Location of the top 10 constraints by total congestion costs: January through March, 2023

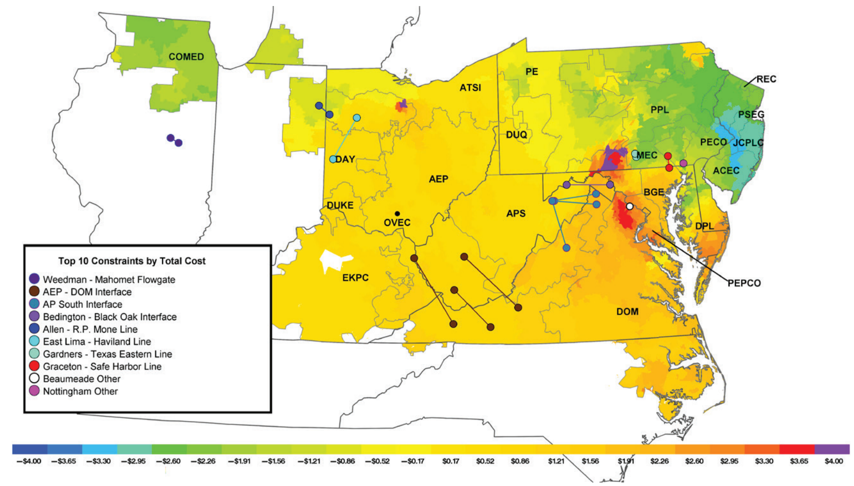


Figure 11-6 shows the locations of the top 10 constraints by balancing congestion costs on a contour map of the real-time load-weighted average CLMP in the first three months of 2023.

Figure 11-6 Location of top 10 constraints by balancing congestion costs: January through March, 2023

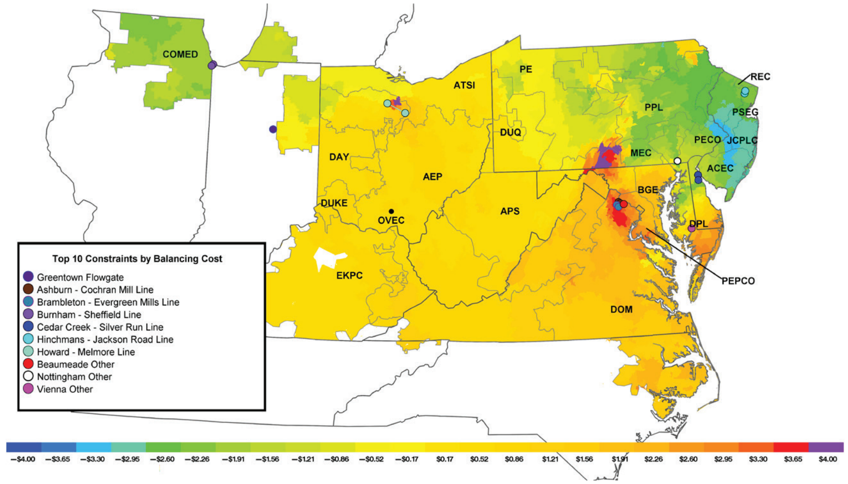
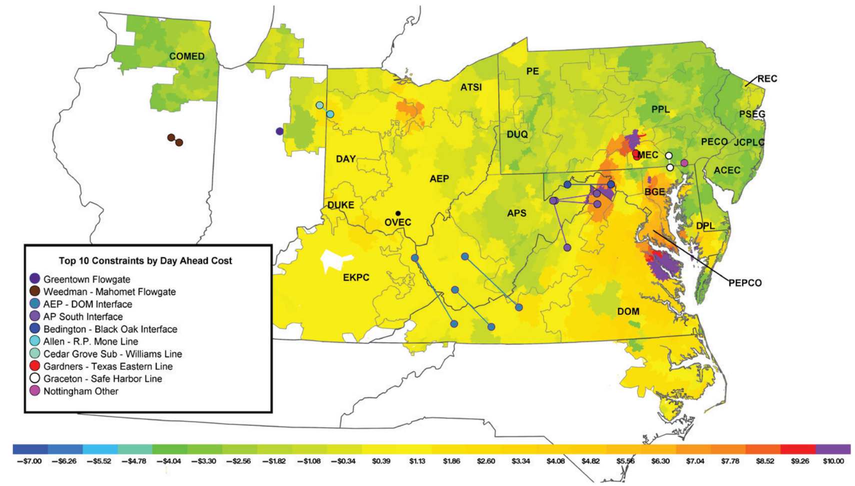


Figure 11-7 shows the locations of the top 10 constraints by day-ahead congestion costs on a contour map of the day-ahead load-weighted average CLMP in the first three months of 2023.

Figure 11-7 Location of top 10 constraints by day-ahead congestion costs: January through March, 2023



Comparing Figure 11-6 (Location of the top 10 constraints by balancing congestion costs) and Figure 11-7 (location of the top 10 constraints by day ahead congestion costs) shows the significant differences between the day ahead and real time market.

Congestion Event Summary: Impact of Changes in UTC Volumes

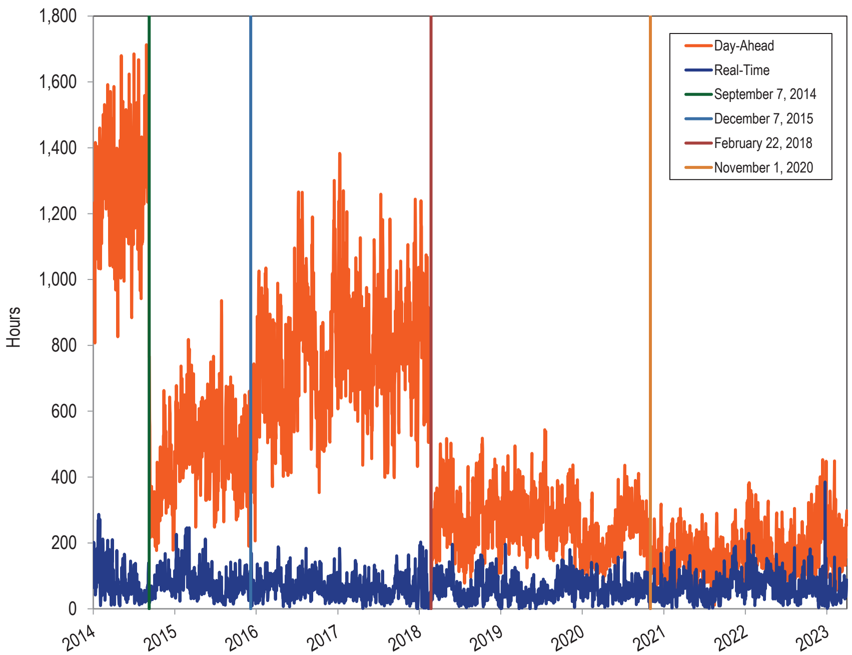
UTCs have a significant impact on congestion events in the day-ahead market and, as a result, contribute to differences between day-ahead and real-time congestion events. The greater the volume of UTCs, the greater the number of congestion events in the day-ahead market and the greater the differences between the day-ahead and real-time congestion events.[31]

31 A series of FERC orders has affected UTC activity which has in turn affected congestion events in the day-ahead market. See Appendix F: Congestion and Marginal Losses.

In the first three months of 2023, the average hourly cleared UTC MW increased by 135.2 percent, compared to the first three months of 2022. Day-ahead congestion event hours decreased by 11.8 percent from 21,091 congestion event hours in the first three months of 2022 to 18,602 congestion event hours in the first three months of 2023 (Table 11-25).

Figure 11-8 shows the daily day-ahead and real-time congestion event hours for January 2014 through March 2023.

Figure 11-8 Daily congestion event hours: January 2014 through March 2023



Marginal Losses

Marginal Loss Accounting

Marginal losses occur in the day-ahead and real-time energy markets. PJM calculates marginal loss costs for each PJM member. The loss cost is based on the applicable day-ahead and real-time marginal loss component of LMP (MLMP). Losses are the difference between what load (withdrawals) pay for energy and what generation (injections) are paid for energy, due to transmission line losses.

Losses increase with distance between sources and sinks and the amount of power moved. Total loss collected (loss surplus) increases with load, holding distance and resistance constant. Every incremental increase in load has to be met with a slightly larger increment of generation. The result is that the total energy losses increase as load increases.

Ignoring interchange, total generation MWh must be greater than total load MWh in any hour in order to provide for losses. Total marginal loss costs, analogous to total congestion costs, are equal to the net of the withdrawal loss charges minus injection loss credits, plus explicit loss charges, incurred in both the day-ahead energy market and the balancing energy market.

Total marginal loss costs can be more accurately thought of as net marginal loss costs. Total marginal loss costs equal implicit marginal loss charges plus explicit marginal loss charges plus net inadvertent loss charges. Implicit marginal loss charges equal withdrawal loss charges minus injection loss credits. Net explicit marginal loss costs are the net marginal loss costs associated with point to point energy transactions. Net inadvertent loss charges are the losses associated with the hourly difference between the net actual energy flow and the net scheduled energy flow into or out of the PJM control area.[32] Unlike the other categories of marginal loss accounting, inadvertent loss charges are costs not directly attributable to specific participants. Inadvertent loss charges are assigned to participants based on real-time load (excluding losses) ratio share.[33] Each of these categories of marginal loss costs is comprised of day-ahead and balancing marginal loss costs.

32 PJM Operating Agreement Schedule 1 §3.7.
33 *Id.*

The accounting definitions can be misleading. Load pays losses. Losses are the difference between what load pays for energy and what generation is paid for energy due to losses. Generation does not pay losses. Some generation receives a price lower than SMP and some generation receives a price greater than SMP due to the MLMP but that does not mean that generation is paying or being paid losses. It means that generation is being paid an LMP that is higher or lower than the system load-weighted, average LMP due to losses on the system.

While PJM accounting focuses on MLMPs, the individual MLMP values at any bus are irrelevant to the calculation of total losses. Total losses are the net surplus revenue that remains after all sources and sinks are credited or charged their LMPs. Changing the components of LMP by electing a different reference bus does not change the LMPs or the difference between LMPs for a given market solution or losses, it merely changes the components of the LMP.

The MLMP component of LMP is the marginal cost of energy, due to losses associated with serving load at the bus. The MLMP at the load weighted reference bus is the marginal cost of energy at the load weighted reference bus (holding the proportion of load at every bus constant). Due to losses, MLMP is non zero at the load reference bus. The LMP at the load reference bus is the system marginal price of energy (SMP) plus the marginal cost of energy due to losses at the reference bus.

Load-weighted LMP components are calculated relative to a load-weighted, average LMP. LMPs at specific load buses will reflect the fact that marginal generators must produce more (or less) energy due to losses to serve that bus than is needed to serve the load weighted reference bus. The LMP at any bus is a function of the SMP, losses and congestion. Relative to the system marginal price (SMP) at the load weighted reference bus, the loss factor can be either positive or negative.

At the load-weighted reference bus, the LMP includes no congestion component, but does include a loss component. The load weighted average MLMP across all load buses, calculated relative to that reference bus is positive. The LMPs at the load buses are a function of marginal generation bus LMPs determined through the least cost security constrained economic dispatch which accounts for transmission constraints and marginal losses.

Other than the effect on the optimal dispatch point, LMP at the marginal generator bus, and therefore the payment to the generator, is not affected by marginal losses. By paying for losses based on marginal instead of average losses at the load bus, a revenue over collection occurs.

The residual difference between total marginal loss related load charges (day-ahead and balancing) and marginal loss related generation credits (day-ahead and balancing) after virtual bids have settled their marginal loss related credits and charges for their day-ahead and balancing positions is total loss. That is, losses are the difference between what withdrawals (load) are paying for energy and what injections (generation) are being paid for energy due to losses, after virtual bids marginal loss related charges and credits are settled at the end of the market day. Load is the source of the net loss surplus after generation is paid and virtuals are settled at the end of the market day. Load pays losses. Generation does not pay losses.

Day-ahead marginal loss costs are based on day-ahead MWh priced at the marginal loss price component of LMP. Balancing marginal loss costs are based on the load or generation deviations between the day-ahead and real-time energy markets priced at the marginal loss price component of LMP in the real-time energy market. If a participant has real-time generation or load that is greater than its day-ahead generation or load then the deviation will be positive. If there is a positive load deviation at a bus where the real-time LMP has a positive marginal loss component, positive balancing marginal loss costs will result. Similarly, if there is a positive load deviation at a bus where real-time LMP has a negative marginal loss component, negative balancing marginal loss costs will result. If a participant has real-time generation or load that is less than its day-ahead generation or load then the deviation will be negative. If there is a negative load deviation at a bus where real-time LMP has a positive marginal loss component, negative balancing marginal loss costs will result. Similarly, if there is a negative load deviation at a bus where real-time LMP has a negative marginal loss component, positive balancing marginal loss costs will result.

The total marginal loss surplus is the remaining loss amount from collection of marginal losses, after accounting for total system energy costs and net residual market adjustments. The marginal loss surplus is allocated to PJM market participants based on real-time load plus export ratio share as marginal loss credits.[34]

Day-Ahead Implicit Load MLMP Charges

- **Day-Ahead Implicit Load MLMP Charges.** Day-ahead implicit load MLMP charges are calculated for all cleared demand, decrement bids and day-ahead energy market sale transactions. Day-ahead implicit load MLMP charges are calculated using MW and the load bus MLMP, the decrement bid MLMP or the MLMP at the source of the sale transaction.
- **Day-Ahead Implicit Generation MLMP Credits.** Day-ahead implicit generation MLMP credits are calculated for all cleared generation and increment offers and day-ahead energy market purchase transactions. Day-ahead implicit generation MLMP credits are calculated using MW and the generator bus MLMP, the increment offer MLMP or the MLMP at the sink of the purchase transaction.
- **Balancing Implicit Load MLMP Charges.** Balancing implicit load MLMP charges are calculated for all deviations between a PJM member's real-time load and energy sale transactions and their day-ahead cleared demand, decrement bids and energy sale transactions. Balancing implicit load MLMP charges are calculated using MW deviations and the real-time MLMP for each bus where a deviation exists.
- **Balancing Implicit Generation MLMP Credits.** Balancing implicit Generation MLMP credits are calculated for all deviations between a PJM member's real-time generation and energy purchase transactions and the day-ahead cleared generation, increment offers and energy purchase transactions. Balancing implicit Generation MLMP credits are calculated using MW deviations and the real-time MLMP for each bus where a deviation exists.
- **Explicit Loss Charges.** Explicit loss charges are the net loss costs associated with point to point energy transactions, including UTCs. These costs equal the product of the transacted MW and MLMP differences between sources (origins) and sinks (destinations) in the day-ahead energy market. Balancing energy market explicit loss costs equal the product of the differences between the real-time and day-ahead transacted MW and the differences between the real-time MLMP at the transactions' sources and sinks.
- **Inadvertent Loss Charges.** Inadvertent loss charges are the net loss charges resulting from the differences between the net actual energy flow and the net scheduled energy flow into or out of the PJM control area each hour. This inadvertent interchange of energy may be positive or negative, where positive interchange typically results in a charge while negative interchange typically results in a credit. Inadvertent loss charges are common costs, not directly attributable to specific participants, that are distributed on a load plus export ratio basis.[35]

Total Marginal Loss Cost

Total marginal loss is the difference between what withdrawals (load) pay for energy and what injections (generation) are paid for energy due to losses, after generation is paid and virtuals' marginal loss related charges and credits are settled. Load pays losses.

The total marginal loss cost in PJM for the first three months of 2023 was $201.2 million, which was comprised of implicit withdrawal MLMP charges of $8.1 million minus implicit injection MLMP credits of -$196.3 million plus explicit loss charges of -$3.2 million plus inadvertent loss charges of $0.0 million (Table 11-34).

Monthly marginal loss costs in the first three months of 2023 ranged from $56.1 million in March to $78.8 million in January. Total marginal loss surplus decreased in the first three months of 2023 by $62.8 million or 48.9 percent from $128.5 million in the first three months of 2022 to $65.7 million in the first three months of 2023.

Table 11-33 shows the total marginal loss component costs and the total PJM billing for January through March, 2008 through 2023.

34 See PJM. "Manual 28: Operating Agreement Accounting," Rev. 89 (Nov. 1, 2022).

35 PJM Operating Agreement Schedule 1 §3.7.

Table 11-33 Total loss component costs (Dollars (Millions)): January through March, 2008 through 2023[36 37]

(Jan - Mar)	Loss Costs	Percent Change	Total PJM Billing	Percent of PJM Billing
2008	$607	NA	$7,718	7.9%
2009	$454	(25.2%)	$7,515	6.0%
2010	$417	(8.2%)	$8,415	5.0%
2011	$410	(1.7%)	$9,584	4.3%
2012	$234	(42.8%)	$6,938	3.4%
2013	$278	18.5%	$7,762	3.6%
2014	$776	179.5%	$21,070	3.7%
2015	$425	(45.2%)	$14,040	3.0%
2016	$170	(60.0%)	$9,500	1.8%
2017	$172	0.9%	$9,710	1.8%
2018	$339	97.9%	$14,520	2.3%
2019	$204	(39.9%)	$11,600	1.8%
2020	$109	(46.8%)	$8,740	1.2%
2021	$210	93.2%	$11,280	1.9%
2022	$393	87.5%	$18,100	2.2%
2023	$201	(48.8%)	$12,030	1.7%

Table 11-34 shows PJM total marginal loss costs by accounting category for January through March, 2008 through 2023. Table 11-35 shows PJM total marginal loss costs by accounting category by market for the first three months of 2008 through 2023.

Table 11-34 Total marginal loss costs by accounting category (Dollars (Millions)): January through March, 2008 through 2023

	Marginal Loss Costs (Millions)				
(Jan - Mar)	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Inadvertent Charges	Total
2008	($52.1)	($634.0)	$25.1	$0.0	$606.9
2009	($21.3)	($460.6)	$14.7	$0.0	$454.0
2010	($3.8)	($414.1)	$6.3	($0.0)	$416.6
2011	($26.5)	($421.2)	$14.9	$0.0	$409.6
2012	($11.2)	($252.1)	($6.6)	$0.0	$234.3
2013	$8.0	($277.8)	($8.2)	($0.0)	$277.6
2014	($15.1)	($813.7)	($22.8)	$0.0	$775.9
2015	($4.0)	($434.0)	($4.9)	$0.0	$425.1
2016	($8.0)	($184.4)	($6.3)	$0.0	$170.1
2017	($13.0)	($196.2)	($11.6)	($0.0)	$171.5
2018	($13.2)	($356.7)	($4.0)	$0.0	$339.4
2019	($13.7)	($220.9)	($3.2)	$0.0	$203.9
2020	($9.8)	($122.1)	($3.8)	($0.0)	$108.5
2021	$2.1	($208.8)	($1.2)	$0.0	$209.7
2022	$85.9	($315.3)	($8.1)	($0.0)	$393.1
2023	$8.1	($196.3)	($3.2)	($0.0)	$201.2

36 The loss costs include net inadvertent charges.
37 In Table 11-33, the MMU uses Total PJM Billing values provided by PJM. For 2019 and after, the Total PJM Billing calculation was modified to better reflect PJM total billing through the PJM settlement process.

Table 11-35 Total marginal loss costs by market (Dollars (Millions)): January through March, 2008 through 2023

	Marginal Loss Costs (Millions)									
	Day-Ahead				Balancing					
(Jan - Mar)	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Inadvertent Charges	Grand Total
2008	($17.1)	($603.7)	$31.3	$617.9	($35.0)	($30.2)	($6.2)	($11.0)	$0.0	$606.9
2009	($23.3)	($457.6)	$30.9	$465.2	$2.1	($3.0)	($16.3)	($11.2)	$0.0	$454.0
2010	($8.5)	($413.5)	$12.8	$417.8	$4.7	($0.6)	($6.5)	($1.2)	($0.0)	$416.6
2011	($37.1)	($430.1)	$26.0	$419.1	$10.6	$8.9	($11.1)	($9.5)	$0.0	$409.6
2012	($16.7)	($256.8)	$8.0	$248.1	$5.6	$4.7	($14.6)	($13.8)	$0.0	$234.3
2013	($0.1)	($288.2)	$8.1	$296.2	$8.1	$10.4	($16.3)	($18.6)	($0.0)	$277.6
2014	($48.6)	($847.4)	$32.3	$831.1	$33.5	$33.7	($55.1)	($55.3)	$0.0	$775.9
2015	($17.4)	($441.6)	$7.8	$432.0	$13.5	$7.6	($12.8)	($6.9)	$0.0	$425.1
2016	($10.7)	($186.3)	$7.6	$183.3	$2.7	$1.9	($14.0)	($13.2)	$0.0	$170.1
2017	($15.1)	($197.5)	$17.5	$199.9	$2.1	$1.3	($29.1)	($28.3)	($0.0)	$171.5
2018	($15.3)	($352.2)	$10.1	$347.0	$2.1	($4.5)	($14.1)	($7.5)	$0.0	$339.4
2019	($13.8)	($219.3)	$14.5	$219.9	$0.1	($1.6)	($17.7)	($16.1)	$0.0	$203.9
2020	($10.0)	($122.6)	$9.5	$122.0	$0.2	$0.4	($13.2)	($13.4)	($0.0)	$108.5
2021	$2.7	($208.8)	$9.0	$220.5	($0.6)	($0.0)	($10.2)	($10.8)	$0.0	$209.7
2022	$95.3	($314.8)	$15.3	$425.4	($9.4)	($0.5)	($23.4)	($32.3)	($0.0)	$393.1
2023	$10.1	($194.3)	$18.4	$222.8	($2.0)	($2.0)	($21.6)	($21.6)	($0.0)	$201.2

Table 11-36 and Table 11-37 show PJM accounting based total loss costs for each transaction type in the first three months of 2023 and 2022.

Virtual transaction loss costs, when positive, measure the total loss costs to virtual transactions and when negative, measure the total loss credits to virtual transactions. In the first three months of 2023, DECs were paid $0.1 million in MLMP credits in the day-ahead market, paid $0.7 million in MLMP in the balancing energy market and paid $0.7 million in total MLMP charges. In the first three months of 2023, INCs paid $6.6 million in MLMP charges in the day-ahead market, were paid $7.7 million in MLMP credits in the balancing energy market and were paid $1.0 million in total MLMP credits. In the first three months of 2023, up to congestion paid $18.8 million in MLMP charges in the day-ahead market, were paid $21.4 million in MLMP credits in the balancing energy market and received $2.7 million in total MLMP credits.

Table 11-36 Total loss costs by transaction type (Dollars (Millions)): January through March, 2023

	Marginal Loss Costs (Millions)									
	Day-Ahead				Balancing					
Transaction Type	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Inadvertent Charges	Grand Total
DEC	($0.1)	$0.0	$0.0	($0.1)	$0.7	$0.0	$0.0	$0.7	$0.0	$0.7
Demand	$10.1	$0.0	$0.0	$10.1	$1.7	$0.0	$0.0	$1.7	$0.0	$11.8
Demand Response	$0.0	$0.0	$0.0	$0.0	($0.0)	$0.0	$0.0	($0.0)	$0.0	($0.0)
Explicit Congestion and Loss Only	$0.0	$0.0	($0.4)	($0.4)	$0.0	$0.0	$0.0	$0.0	$0.0	($0.4)
Export	($2.4)	$0.0	($0.1)	($2.5)	($2.3)	$0.0	($0.1)	($2.4)	$0.0	($4.9)
Generation	$0.0	($188.7)	$0.0	$188.7	$0.0	($5.0)	$0.0	$5.0	$0.0	$193.7
Import	$0.0	($1.6)	$0.0	$1.6	$0.0	($2.6)	$0.0	$2.6	$0.0	$4.2
INC	$0.0	($6.6)	$0.0	$6.6	$0.0	$7.7	$0.0	($7.7)	$0.0	($1.0)
Internal Bilateral	$2.4	$2.6	$0.1	$0.0	($2.1)	($2.1)	$0.0	($0.0)	$0.0	($0.0)
Up to Congestion	$0.0	$0.0	$18.8	$18.8	$0.0	$0.0	($21.4)	($21.4)	$0.0	($2.7)
Wheel In	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	($0.1)	($0.1)	$0.0	($0.1)
Total	$10.1	($194.3)	$18.4	$222.8	($2.0)	($2.0)	($21.6)	($21.6)	$0.0	$201.2

Table 11-37 Total loss costs by transaction type (Dollars (Millions)): January through March, 2022

	Marginal Loss Costs (Millions)									
	Day-Ahead				Balancing					
Transaction Type	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Inadvertent Charges	Grand Total
DEC	$12.2	$0.0	$0.0	$12.2	($6.9)	$0.0	$0.0	($6.9)	$0.0	$5.3
Demand	$59.4	$0.0	$0.0	$59.4	$2.1	$0.0	$0.0	$2.1	$0.0	$61.6
Demand Response	($0.0)	$0.0	$0.0	($0.0)	$0.0	$0.0	$0.0	$0.0	$0.0	($0.0)
Explicit Congestion and Loss Only	$0.0	$0.0	($0.7)	($0.7)	$0.0	$0.0	($0.0)	($0.0)	$0.0	($0.7)
Export	$3.1	$0.0	($0.1)	$3.0	($2.5)	$0.0	$0.5	($2.0)	$0.0	$1.0
Generation	$0.0	($327.5)	$0.0	$327.5	$0.0	($2.8)	$0.0	$2.8	$0.0	$330.4
Import	$0.0	($1.0)	$0.0	$1.0	$0.0	($7.0)	$0.0	$7.0	$0.0	$8.0
INC	$0.0	($7.1)	$0.0	$7.1	$0.0	$11.5	$0.0	($11.5)	$0.0	($4.3)
Internal Bilateral	$20.5	$20.9	$0.3	$0.0	($2.1)	($2.1)	$0.0	($0.0)	$0.0	($0.0)
Up to Congestion	$0.0	$0.0	$15.8	$15.8	$0.0	$0.0	($23.8)	($23.8)	$0.0	($8.0)
Wheel In	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	($0.1)	($0.1)	$0.0	($0.1)
Total	$95.3	($314.8)	$15.3	$425.4	($9.4)	($0.5)	($23.4)	($32.3)	$0.0	$393.1

Table 11-38 compares MLMP credits and charges for each transaction type between the dispatch run and pricing run in the first three months of 2023. Total MLMP charges to generation increased by $0.4 million, and total MLMP charges to demand increased by $0.1 million from the dispatch run to the pricing run. The total MLMP charges to DECs decreased by $0.0 million, the total MLMP credits to INCs increased by $0.2 million and the total CLMP credits to UTCs increased by $1.1 million from the dispatch run to the pricing run.

Table 11-38 Total loss costs by dispatch and pricing run (Dollars (Millions)): January through March, 2023

	Marginal Loss Costs (Millions)								
	Dispatch Run			Pricing Run			Difference		
Transaction Type	Day-Ahead	Balancing	Total	Day-Ahead	Balancing	Total	Day-Ahead	Balancing	Total
DEC	($0.1)	$0.7	$0.7	($0.1)	$0.7	$0.7	$0.0	($0.0)	($0.0)
Demand	$10.1	$1.6	$11.6	$10.1	$1.7	$11.8	$0.0	$0.1	$0.1
Demand Response	$0.0	($0.0)	($0.0)	$0.0	($0.0)	($0.0)	$0.0	($0.0)	($0.0)
Explicit Congestion and Loss Only	($0.4)	$0.0	($0.4)	($0.4)	$0.0	($0.4)	($0.0)	$0.0	($0.0)
Export	($2.5)	($2.4)	($4.8)	($2.5)	($2.4)	($4.9)	$0.0	($0.0)	($0.0)
Generation	$188.4	$4.9	$193.3	$188.7	$5.0	$193.7	$0.3	$0.1	$0.4
Import	$1.6	$2.5	$4.0	$1.6	$2.6	$4.2	$0.0	$0.1	$0.1
INC	$6.6	($7.4)	($0.8)	$6.6	($7.7)	($1.0)	$0.0	($0.2)	($0.2)
Internal Bilateral	$0.0	($0.0)	($0.0)	$0.0	($0.0)	($0.0)	$0.0	($0.0)	($0.0)
Up to Congestion	$18.8	($20.4)	($1.6)	$18.8	($21.4)	($2.7)	$0.0	($1.1)	($1.1)
Wheel In	$0.0	($0.1)	($0.1)	$0.0	($0.1)	($0.1)	$0.0	($0.0)	($0.0)
Total	$222.4	($20.5)	$201.9	$222.8	($21.6)	$201.2	$0.4	($1.1)	($0.7)

Monthly Marginal Loss Costs

Table 11-39 shows a monthly summary of marginal loss costs by market type for January 2022 through March 2023.

Table 11-39 Monthly marginal loss costs (Millions): January 2022 through March 2023

	Marginal Loss Costs (Millions)							
	2022				2023			
	Day-Ahead	Balancing	Inadvertent Charges	Total	Day-Ahead	Balancing	Inadvertent Charges	Total
Jan	$213.0	($18.4)	$0.0	$194.6	$88.3	($9.5)	($0.0)	$78.8
Feb	$120.9	($8.1)	$0.0	$112.8	$73.0	($6.7)	($0.0)	$66.3
Mar	$91.5	($5.8)	($0.0)	$85.7	$61.5	($5.4)	$0.0	$56.1
Apr	$103.6	($4.1)	($0.0)	$99.5				
May	$155.8	($8.4)	($0.0)	$147.4				
Jun	$188.0	($10.1)	($0.0)	$177.9				
Jul	$253.2	($14.7)	$0.0	$238.5				
Aug	$276.9	($19.5)	($0.0)	$257.4				
Sep	$170.7	($12.5)	($0.0)	$158.2				
Oct	$106.9	($6.9)	($0.0)	$100.1				
Nov	$114.2	($8.4)	($0.0)	$105.8				
Dec	$257.6	($17.5)	($0.0)	$240.1				
Total	$2,052.3	($134.2)	($0.0)	$1,918.0	$222.8	($21.6)	($0.0)	$201.2

Figure 11-9 shows PJM monthly marginal loss costs for January 2008 through March 2023.

Figure 11-9 Monthly marginal loss cost (Dollars (Millions)): January 2008 through March 2023

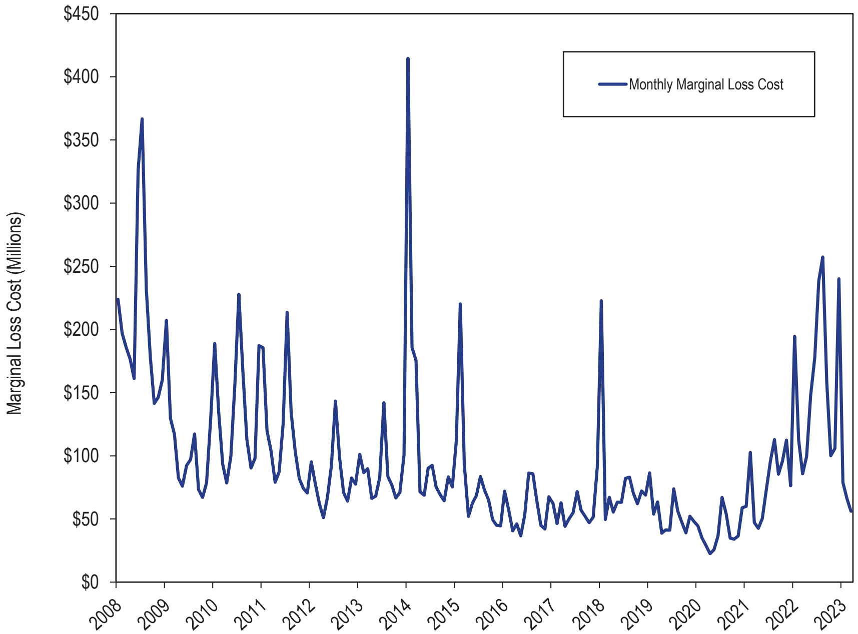


Table 11-40 shows the monthly total loss charges for each virtual transaction type for January 2022 through March 2023. In the first three months of 2023, 88.2 percent of the total credits to virtuals went to UTCs, compared to 94.9 percent in the first three months of 2022.

Table 11-40 Monthly loss charges by virtual transaction type (Dollars (Millions)): January 2022 through March 2023

		Marginal Loss Charges (Millions)									
		DEC			INC			Up to Congestion			
Year		Day-Ahead	Balancing	Total	Day-Ahead	Balancing	Total	Day-Ahead	Balancing	Total	Grand Total
2022	Jan	$6.8	($5.6)	$1.2	$2.9	($4.9)	($2.0)	$7.2	($10.4)	($3.1)	($3.9)
	Feb	$5.1	($1.9)	$3.3	$1.7	($3.0)	($1.3)	$5.7	($7.8)	($2.1)	($0.1)
	Mar	$0.3	$0.6	$0.9	$2.5	($3.5)	($1.0)	$2.8	($5.6)	($2.8)	($3.0)
	Apr	($0.9)	$1.2	$0.3	$3.4	($4.3)	($0.9)	$4.0	($5.7)	($1.7)	($2.3)
	May	($1.6)	$1.8	$0.2	$4.5	($4.7)	($0.2)	$7.6	($9.0)	($1.4)	($1.4)
	Jun	($2.3)	$2.6	$0.3	$2.9	($4.9)	($1.9)	$8.5	($14.2)	($5.7)	($7.3)
	Jul	($1.3)	$2.4	$1.1	$3.7	($5.1)	($1.4)	$10.3	($14.8)	($4.5)	($4.8)
	Aug	($0.8)	$2.2	$1.5	$3.6	($6.1)	($2.5)	$12.6	($20.0)	($7.4)	($8.5)
	Sep	($1.6)	$2.2	$0.7	$3.0	($3.5)	($0.6)	$9.0	($12.1)	($3.1)	($3.0)
	Oct	($0.8)	$1.4	$0.6	$3.6	($3.7)	($0.1)	$5.6	($7.0)	($1.4)	($1.0)
	Nov	($1.1)	$1.2	$0.1	$5.1	($5.1)	($0.1)	$9.2	($9.6)	($0.4)	($0.3)
	Dec	($0.0)	($0.4)	($0.4)	$5.1	($11.3)	($6.2)	$19.1	($32.5)	($13.4)	($20.0)
	Total	$1.9	$7.8	$9.7	$42.0	($60.2)	($18.2)	$101.7	($148.8)	($47.1)	($55.7)
2023	Jan	($0.1)	$0.2	$0.1	$2.4	($3.0)	($0.5)	$8.2	($9.9)	($1.7)	($2.1)
	Feb	$0.6	($0.2)	$0.5	$2.4	($2.5)	($0.1)	$5.6	($5.8)	($0.3)	$0.1
	Mar	($0.6)	$0.7	$0.1	$1.9	($2.2)	($0.4)	$5.0	($5.7)	($0.7)	($1.0)
	Total	($0.1)	$0.7	$0.7	$6.6	($7.7)	($1.0)	$18.8	($21.4)	($2.7)	($3.0)

Marginal Loss Costs and Loss Credits

Total marginal loss surplus is calculated by adding the total system energy costs (which are negative), the total marginal loss costs (which are positive) and net residual market adjustments (which can be net positive or negative). The total system energy costs are equal to the net implicit energy charges (implicit withdrawal charges minus implicit injection credits) plus net inadvertent energy charges. Total marginal loss costs are equal to the net implicit marginal loss charges (implicit load MLMP charges less implicit generation MLMP credits) plus net explicit loss charges plus net inadvertent loss charges.

Ignoring interchange, total generation MWh must be greater than total load MWh in any hour in order to provide for losses. Since the hourly integrated energy component of LMP is the same for every bus within every hour, the net energy bill is negative (ignoring net interchange), with more injection credits than withdrawal charges in every hour. The greater the level of load the greater the difference between energy charges collected from load (SMP x load MW) and credited to generation (SMP x generation MW). Total system energy costs plus total marginal loss costs plus net residual market adjustments equal marginal loss credits which are distributed to the PJM market participants according to the ratio of their real-time load plus their real-time exports to total PJM real-time load plus real-time exports as marginal loss credits. The net residual market adjustment is calculated as known day-ahead error value minus day-ahead loss MW congestion value and minus balancing loss MW congestion value.

Table 11-41 shows the total system energy costs, the total marginal loss costs collected, the net residual market adjustments and total marginal loss surplus redistributed for January through March, 2008 through 2023. The total marginal loss surplus decreased by $62.8 million or 48.9 percent in the first three months of 2023 from the first three months of 2022.

Table 11-41 Marginal loss surplus (Dollars (Millions)): January through March, 2008 through 2023[38]

	Marginal Loss Surplus (Millions)					
			Net Residual Market Adjustments			
(Jan - Mar)	System Energy Cost	Marginal Loss Costs	Known Day-Ahead Error	Day-Ahead Loss MW Congestion	Balancing Loss MW Congestion	Total Marginal Loss Surplus
2008	($288.2)	$606.9	$0.0	$0.0	$0.0	$318.7
2009	($218.3)	$454.0	($0.0)	($0.4)	($0.1)	$236.2
2010	($207.6)	$416.6	$0.0	($0.9)	($0.0)	$209.9
2011	($209.9)	$409.6	$0.0	$0.0	($0.0)	$199.7
2012	($136.4)	$234.3	($0.0)	($0.5)	$0.0	$98.3
2013	($177.9)	$277.6	$0.1	$0.3	$0.0	$99.4
2014	($515.3)	$775.9	$0.0	$3.1	$0.2	$257.2
2015	($271.7)	$425.1	($0.5)	$2.9	($0.0)	$150.0
2016	($113.6)	$170.1	$0.0	$0.8	($0.0)	$55.7
2017	($122.1)	$171.5	$0.0	$0.2	($0.0)	$49.2
2018	($226.6)	$339.4	($0.0)	$1.2	($0.0)	$111.6
2019	($136.3)	$203.9	$0.0	$0.7	($0.0)	$66.9
2020	($75.3)	$108.5	($0.0)	($0.0)	($0.0)	$33.2
2021	($131.5)	$209.7	($0.0)	$1.0	($0.0)	$77.2
2022	($260.8)	$393.1	($0.0)	$3.8	($0.0)	$128.5
2023	($135.6)	$201.2	$0.0	($0.0)	($0.0)	$65.7

System Energy Costs

Energy Accounting

The system energy component of LMP is the system reference bus LMP, also called the system marginal price (SMP). The system energy cost is based on the day-ahead and real-time energy components of LMP. Total system energy costs, analogous to total congestion costs or total loss costs, are equal to the withdrawal energy charges minus injection energy credits, in both the day-ahead energy market and the balancing energy market, plus net inadvertent energy charges. Total system energy costs can be more accurately thought of as net system energy costs.

Total System Energy Costs

The total system energy cost for the first three months of 2023 was -$135.6 million, which was comprised of implicit withdrawal energy charges of $8,785.6 million, implicit injection energy credits of $8,920.1 million, explicit energy charges of $0.0 million and inadvertent energy charges of -$1.1 million. The monthly system energy costs for the first three months of 2023 ranged from -$52.9 million in January to -$37.5 million in March.

Table 11-42 shows total system energy costs and total PJM billing, for January through March, 2008 through 2023.

Table 11-42 Total system energy costs (Dollars (Millions)): January through March, 2008 through 2023[39 40]

(Jan - Mar)	System Energy Costs	Percent Change	Total PJM Billing	Percent of PJM Billing
2008	($288)	NA	$7,718	(3.7%)
2009	($218)	(24.2%)	$7,515	(2.9%)
2010	($208)	(4.9%)	$8,415	(2.5%)
2011	($210)	1.1%	$9,584	(2.2%)
2012	($136)	(35.0%)	$6,938	(2.0%)
2013	($178)	30.4%	$7,762	(2.3%)
2014	($515)	189.7%	$21,070	(2.4%)
2015	($272)	(47.3%)	$14,040	(1.9%)
2016	($114)	(58.2%)	$9,500	(1.2%)
2017	($122)	7.5%	$9,710	(1.3%)
2018	($227)	85.6%	$14,520	(1.6%)
2019	($136)	(39.8%)	$11,600	(1.2%)
2020	($75)	(44.8%)	$8,740	(0.9%)
2021	($132)	74.6%	$11,280	(1.2%)
2022	($261)	98.3%	$18,100	(1.4%)
2023	($136)	(48.0%)	$12,030	(1.1%)

System energy costs for January through March, 2008 through 2023 are shown in Table 11-43 and Table 11-44. Table 11-43 shows PJM system energy costs by accounting category and Table 11-44 shows PJM system energy costs by market category.

38 The net residual market adjustments included in the table are comprised of the known day-ahead error value minus the sum of the day-ahead loss MW congestion value, balancing loss MW congestion value and measurement error caused by missing data.

39 The system energy costs include net inadvertent charges.

40 In Table 11-42, the MMU uses Total PJM Billing values provided by PJM. For 2019 and after, the Total PJM Billing calculation was modified to better reflect PJM total billing through the PJM settlement process.

Table 11-43 Total system energy costs by accounting category (Dollars (Millions)): January through March, 2008 through 2023

	System Energy Costs (Millions)				
(Jan - Mar)	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Inadvertent Charges	Total
2008	$28,435.7	$28,723.9	$0.0	$0.0	($288.2)
2009	$14,058.4	$14,277.4	$0.0	$0.7	($218.3)
2010	$13,424.4	$13,629.0	$0.0	($3.0)	($207.6)
2011	$11,943.9	$12,160.7	$0.0	$6.9	($209.9)
2012	$8,485.4	$8,628.7	$0.0	$6.8	($136.4)
2013	$10,357.2	$10,535.1	$0.0	($0.0)	($177.9)
2014	$28,506.2	$29,014.7	$0.0	($6.9)	($515.3)
2015	$15,702.1	$15,976.4	$0.0	$2.6	($271.7)
2016	$7,764.7	$7,879.3	$0.0	$1.0	($113.6)
2017	$8,789.3	$8,910.2	$0.0	($1.3)	($122.1)
2018	$13,910.8	$14,142.2	$0.0	$4.7	($226.6)
2019	$8,856.0	$8,993.5	$0.0	$1.2	($136.3)
2020	$5,541.1	$5,616.0	$0.0	($0.4)	($75.3)
2021	$8,663.3	$8,795.5	$0.0	$0.6	($131.5)
2022	$15,137.8	$15,398.2	$0.0	($0.4)	($260.8)
2023	$8,785.6	$8,920.1	$0.0	($1.1)	($135.6)

Table 11-44 Total system energy costs by market (Dollars (Millions)): January through March, 2008 through 2023

	System Energy Costs (Millions)									
	Day-Ahead				Balancing					
(Jan - Mar)	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Inadvertent Charges	Grand Total
2008	$20,253.8	$20,579.6	$0.0	($325.8)	$8,182.0	$8,144.3	$0.0	$37.6	$0.0	($288.2)
2009	$14,129.6	$14,375.6	$0.0	($246.0)	($71.2)	($98.2)	$0.0	$27.0	$0.7	($218.3)
2010	$13,408.9	$13,619.2	$0.0	($210.2)	$15.5	$9.8	$0.0	$5.6	($3.0)	($207.6)
2011	$12,055.5	$12,259.3	$0.0	($203.9)	($111.6)	($98.6)	$0.0	($12.9)	$6.9	($209.9)
2012	$8,534.4	$8,649.0	$0.0	($114.6)	($49.0)	($20.4)	$0.0	($28.6)	$6.8	($136.4)
2013	$10,387.2	$10,580.9	$0.0	($193.7)	($29.9)	($45.8)	$0.0	$15.9	($0.0)	($177.9)
2014	$28,412.1	$29,082.9	$0.0	($670.9)	$94.2	($68.3)	$0.0	$162.4	($6.9)	($515.3)
2015	$15,764.8	$16,077.5	$0.0	($312.6)	($62.7)	($101.1)	$0.0	$38.4	$2.6	($271.7)
2016	$7,847.5	$7,997.9	$0.0	($150.4)	($82.8)	($118.6)	$0.0	$35.8	$1.0	($113.6)
2017	$8,927.5	$9,111.3	$0.0	($183.8)	($138.1)	($201.1)	$0.0	$63.0	($1.3)	($122.1)
2018	$13,877.2	$14,123.7	$0.0	($246.5)	$33.6	$18.5	$0.0	$15.1	$4.7	($226.6)
2019	$8,965.4	$9,131.8	$0.0	($166.4)	($109.4)	($138.4)	$0.0	$28.9	$1.2	($136.3)
2020	$5,612.2	$5,708.5	$0.0	($96.3)	($71.1)	($92.5)	$0.0	$21.4	($0.4)	($75.3)
2021	$8,749.4	$8,901.4	$0.0	($152.0)	($86.0)	($105.9)	$0.0	$19.8	$0.6	($131.5)
2022	$15,372.2	$15,651.2	$0.0	($279.1)	($234.4)	($253.0)	$0.0	$18.7	($0.4)	($260.8)
2023	$8,872.5	$9,054.2	$0.0	($181.7)	($86.9)	($134.1)	$0.0	$47.2	($1.1)	($135.6)

Table 11-45 and Table 11-46 show the total system energy costs for each transaction type in the first three months of 2023 and 2022. In the first three months of 2023, generation was paid $6,437.4 million and demand paid $6,060.2 million in net energy payment. In the first three months of 2022, generation was paid $11,300.9 million and demand paid $10,615.0 million in net energy payment.

Table 11-45 Total system energy costs by transaction type (Dollars (Millions)): January through March, 2023

	System Energy Costs (Millions)								
	Day-Ahead				Balancing				
Transaction Type	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Grand Total
DEC	$327.6	$0.0	$0.0	$327.6	($307.7)	$0.0	$0.0	($307.7)	$19.9
Demand	$6,003.7	$0.0	$0.0	$6,003.7	$56.5	$0.0	$0.0	$56.5	$6,060.2
Demand Response	($0.4)	$0.0	$0.0	($0.4)	$0.4	$0.0	$0.0	$0.4	$0.0
Export	$263.4	$0.0	$0.0	$263.4	$111.5	$0.0	$0.0	$111.5	$374.9
Generation	$0.0	$6,433.2	$0.0	($6,433.2)	$0.0	$4.2	$0.0	($4.2)	($6,437.4)
Import	$0.0	$44.1	$0.0	($44.1)	$0.0	$90.9	$0.0	($90.9)	($135.0)
INC	$0.0	$298.7	$0.0	($298.7)	$0.0	($281.7)	$0.0	$281.7	($17.0)
Internal Bilateral	$2,278.2	$2,278.2	$0.0	($0.0)	$45.2	$45.2	$0.0	$0.0	$0.0
Wheel In	$0.0	$0.0	$0.0	$0.0	$0.0	$7.2	$0.0	($7.2)	($7.2)
Wheel Out	$0.0	$0.0	$0.0	$0.0	$7.2	$0.0	$0.0	$7.2	$7.2
Total	$8,872.5	$9,054.2	$0.0	($181.7)	($86.9)	($134.1)	$0.0	$47.2	($134.5)

Table 11-46 Total system energy costs by transaction type by (Dollars (Millions)): January through March, 2022

	System Energy Costs (Millions)								
	Day-Ahead				Balancing				
Transaction Type	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Implicit Withdrawal Charges	Implicit Injection Credits	Explicit Charges	Total	Grand Total
DEC	$713.0	$0.0	$0.0	$713.0	($725.1)	$0.0	$0.0	($725.1)	($12.1)
Demand	$10,386.7	$0.0	$0.0	$10,386.7	$228.3	$0.0	$0.0	$228.3	$10,615.0
Demand Response	($0.4)	$0.0	$0.0	($0.4)	$0.4	$0.0	$0.0	$0.4	$0.0
Export	$469.0	$0.0	$0.0	$469.0	$215.0	$0.0	$0.0	$215.0	$684.0
Generation	$0.0	$11,431.4	$0.0	($11,431.4)	$0.0	($130.5)	$0.0	$130.5	($11,300.9)
Import	$0.0	$30.1	$0.0	($30.1)	$0.0	$217.5	$0.0	($217.5)	($247.6)
INC	$0.0	$386.0	$0.0	($386.0)	$0.0	($387.1)	$0.0	$387.1	$1.1
Internal Bilateral	$3,803.8	$3,803.8	$0.0	($0.0)	$39.4	$39.4	$0.0	$0.0	($0.0)
Wheel In	$0.0	$0.0	$0.0	$0.0	$0.0	$7.7	$0.0	($7.7)	($7.7)
Wheel Out	$0.0	$0.0	$0.0	$0.0	$7.7	$0.0	$0.0	$7.7	$7.7
Total	$15,372.2	$15,651.2	$0.0	($279.1)	($234.4)	($253.0)	$0.0	$18.7	($260.4)

Table 11-47 compares the total system energy costs for each transaction type between the dispatch run and the pricing run in the first three months of 2023. The system energy charges to demand increased $11.2 million, and the energy credits to generation increased $8.7 million from the dispatch run to the pricing run. The energy charges to DEC decreased $8.7 million, the energy credits to INC decreased $7.4 million from the dispatch run to the pricing run.

Table 11-47 Total system energy costs by dispatch and pricing run (Dollars (Millions)): January through March, 2023

System Energy Costs (Millions)									
	Dispatch Run			Pricing Run			Difference		
Transaction Type	Day-Ahead	Balancing	Total	Day-Ahead	Balancing	Total	Day-Ahead	Balancing	Total
DEC	$327.0	($298.4)	$28.6	$327.6	($307.7)	$19.9	$0.6	($9.3)	($8.7)
Demand	$5,995.5	$53.5	$6,049.0	$6,003.7	$56.5	$6,060.2	$8.2	$3.0	$11.2
Demand Response	($0.4)	$0.4	($0.0)	($0.4)	$0.4	$0.0	($0.0)	$0.0	$0.0
Export	$263.0	$109.3	$372.3	$263.4	$111.5	$374.9	$0.4	$2.3	$2.6
Generation	($6,424.3)	($4.5)	($6,428.8)	($6,433.2)	($4.2)	($6,437.4)	($9.0)	$0.3	($8.7)
Import	($44.0)	($88.0)	($132.0)	($44.1)	($90.9)	($135.0)	($0.1)	($3.0)	($3.0)
INC	($298.3)	$274.0	($24.4)	($298.7)	$281.7	($17.0)	($0.3)	$7.7	$7.4
Internal Bilateral	($0.0)	($0.0)	($0.0)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Wheel In	$0.0	($7.1)	($7.1)	$0.0	($7.2)	($7.2)	$0.0	($0.2)	($0.2)
Wheel Out	$0.0	$7.1	$7.1	$0.0	$7.2	$7.2	$0.0	$0.2	$0.2
Total	($181.4)	$46.2	($135.3)	($181.7)	$47.2	($134.5)	($0.3)	$1.1	$0.8

Monthly System Energy Costs

Table 11-48 shows a monthly summary of system energy costs by market type for January 2022 through March 2023. Total balancing system energy costs in the first three months of 2023 increased in every month compared to the first three months of 2022. Monthly total system energy costs in the first three months of 2023 ranged from -$52.9 million in January to -$37.5 million in March.

Table 11-48 Monthly system energy costs (Dollars (Millions)): January 2022 through March 2023

System Energy Costs (Millions)								
	2022				2023			
	Day-Ahead	Balancing	Inadvertent Charges	Total	Day-Ahead	Balancing	Inadvertent Charges	Total
Jan	($139.7)	$13.2	($0.1)	($126.5)	($73.0)	$20.8	($0.7)	($52.9)
Feb	($74.7)	$0.5	($0.1)	($74.3)	($59.1)	$14.4	($0.4)	($45.1)
Mar	($64.7)	$4.9	($0.3)	($60.0)	($49.6)	$12.1	$0.0	($37.5)
Apr	($78.1)	$9.0	($1.1)	($70.2)				
May	($114.4)	$15.7	($0.4)	($99.1)				
Jun	($138.0)	$17.1	($0.7)	($121.6)				
Jul	($177.8)	$22.4	$0.6	($154.9)				
Aug	($201.6)	$34.1	($1.1)	($168.6)				
Sep	($127.7)	$25.7	($1.9)	($103.9)				
Oct	($81.4)	$15.3	($1.0)	($67.1)				
Nov	($95.2)	$24.9	($1.3)	($71.6)				
Dec	($192.8)	$42.2	($13.7)	($164.3)				
Total	($1,486.2)	$225.0	($21.0)	($1,282.1)	($181.7)	$47.2	($1.1)	($135.6)

Figure 11-10 shows PJM monthly system energy costs for January 2008 through March 2023. Ignoring interchange, total generation MWh must be greater than total load MWh in any hour in order to provide for losses. Since the hourly integrated energy component of LMP (SMP) is the same for every bus in the market in every hour, the net energy bill is always negative (ignoring net interchange): (SMP x withdrawals + SMP x injections) < 0.) Assuming power balance is maintained in the presence of losses, the greater the level of load the greater the difference between energy charges collected from load (SMP x load MW) and credited to generation (SMP x generation MW). With higher load levels, there are generally higher SMPs and more negative total energy charges.

Figure 11-10 Monthly system energy costs (Millions): January 2008 through March 2023

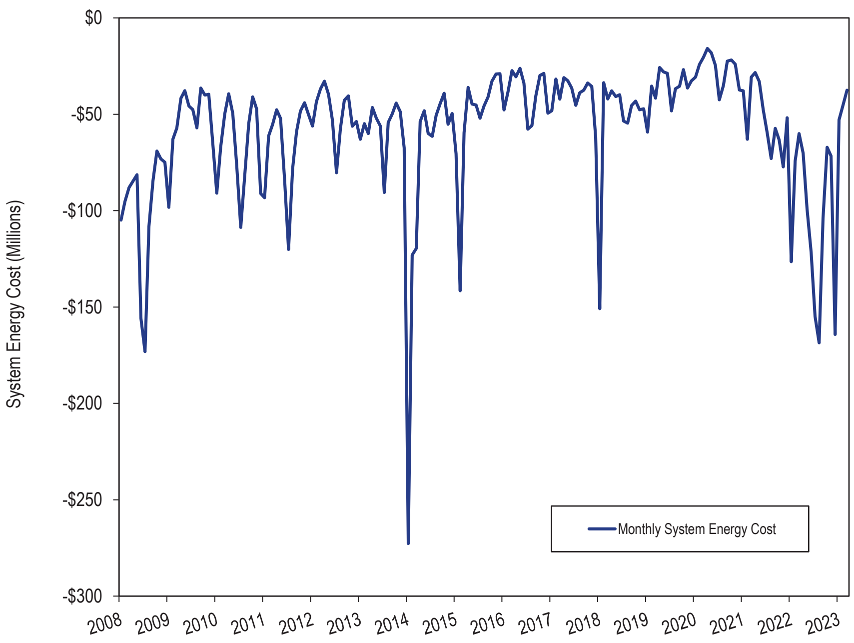


Table 11-49 shows the monthly total system energy costs for each virtual transaction type in the first three months of 2023 and year of 2022. In the first three months of 2023, DECs paid $327.6 million in energy charges compared to $713.0 million in the first three months of 2022 in the day-ahead market, were paid $307.7 million in energy credits compared to $725.1 million in the first three months of 2022 in the balancing energy market and paid $19.9 million in total energy charges compared to $12.1 million in total energy credits in the first three months of 2022. In the first three months of 2023, INCs were paid $298.7 million in energy credits compared to $386.0 million in the first three months of 2022 in the day-ahead market, paid $281.7 million in energy charges compared to $387.1 million in the first three months of 2022 in the balancing market and were paid $17.0 million in total energy credits compared to $1.1 million in total energy charges in the first three months of 2022. The system energy costs are zero for UTCs because the system energy costs for UTCs equal the difference in the energy component between source and sink and the energy component is the same at all buses.

Table 11-49 Monthly energy charges by virtual transaction type (Dollars (Millions)): January 2022 through March 2023

		Energy Charges (Millions)						
		DEC			INC			
Year		Day-Ahead	Balancing	Total	Day-Ahead	Balancing	Total	Grand Total
2022	Jan	$312.1	($344.7)	($32.5)	($133.4)	$147.1	$13.7	($18.9)
	Feb	$207.9	($196.5)	$11.4	($119.5)	$111.8	($7.6)	$3.7
	Mar	$193.0	($183.9)	$9.1	($133.1)	$128.2	($4.9)	$4.2
	Apr	$180.0	($177.9)	$2.1	($179.0)	$177.1	($1.9)	$0.2
	May	$318.1	($319.0)	($0.9)	($211.9)	$211.1	($0.8)	($1.7)
	Jun	$316.0	($344.9)	($28.9)	($215.9)	$232.6	$16.7	($12.2)
	Jul	$317.4	($306.8)	$10.6	($218.4)	$209.2	($9.2)	$1.4
	Aug	$380.9	($403.6)	($22.7)	($236.1)	$253.6	$17.5	($5.2)
	Sep	$369.1	($348.0)	$21.1	($191.6)	$180.8	($10.8)	$10.3
	Oct	$211.9	($204.0)	$7.9	($154.7)	$147.3	($7.3)	$0.6
	Nov	$180.8	($172.3)	$8.6	($178.8)	$173.1	($5.8)	$2.8
	Dec	$289.8	($465.9)	($176.1)	($204.9)	$281.3	$76.4	($99.7)
	Total	$3,277.1	($3,467.5)	($190.4)	($2,177.3)	$2,253.2	$75.9	($114.5)
2023	Jan	$124.3	($121.1)	$3.2	($105.9)	$103.3	($2.6)	$0.7
	Feb	$102.2	($84.4)	$17.8	($98.3)	$84.1	($14.1)	$3.7
	Mar	$101.0	($102.2)	($1.2)	($94.5)	$94.2	($0.3)	($1.5)
	Total	$327.6	($307.7)	$19.9	($298.7)	$281.7	($17.0)	$2.9

Generation and Transmission Planning[1]

Overview

Generation Interconnection Planning

Existing Generation Mix

- As of March 31, 2023, PJM had a total installed capacity of 198,657.1 MW, of which 44,329.4 MW (22.3 percent) are coal fired steam units, 56,278.2 MW (28.3 percent) are combined cycle units and 33,452.6 MW (16.8 percent) are nuclear units. This measure of installed capacity differs from capacity market installed capacity because it includes energy only units, excludes all external units, and uses nameplate values for solar and wind resources.
- Of the 198,657.1 MW of installed capacity, 71,676.3 MW (36.1 percent) are from units older than 40 years, of which 34,642.3 MW (48.3 percent) are coal fired steam units, 191.0 MW (0.3 percent) are combined cycle units and 19,720.6 MW (27.5 percent) are nuclear units.

Generation Retirements[2]

- There are 54,355.9 MW of generation that have been, or are planned to be, retired between 2011 and 2026, of which 40,623.8 MW (74.7 percent) are coal fired steam units. Coal unit retirements are primarily a result of the inability of coal units to compete with efficient combined cycle units burning low cost natural gas.
- In the first three months of 2023, there were no generation retirements.
- As of March 31, 2023, there are 6,863.9 MW of generation that have requested retirement after March 31, 2023, of which 1,522.2 MW (22.2 percent) are located in the ATSI Zone. Of the generation requesting retirement in the ATSI Zone, 1,490.0 MW (97.9 percent) are coal fired steam units.

Generation Queue[3]

- On November 29, 2022, the Commission issued an order accepting PJM's tariff revisions to improve the queue process.[4] The new queue process includes modifications to implement a cluster/cycle based processing method to replace the first in/first out processing method.[5] This change will allow projects to move forward based on a first ready/first out analysis, where readiness is demonstrated through site control and financial milestones and there is an option to exit the study process early based on system impacts.
- As of March 31, 2023, 288,157.8 MW were in generation request queues in the status of active, under construction or suspended, an increase of 665.1 MW (0.2 percent) from the 287,492.7 MW at the end of 2022.[6] Based on historical completion rates, 42,640.7 MW (14.8 percent) of new generation in the queue are expected to go into service. In the first three months of 2023, the AI2 queue window closed. As projects move through the queue process, projects can be removed from the queue due to incomplete or invalid data, withdrawn by the market participant or placed in service.
- As of March 31, 2023, 7,901 projects, representing 821,128.2 MW, have entered the queue process since its inception in 1998. Of those, 1,070 projects, representing 81,630.1 MW, went into service. Of the projects that entered the queue process, 3,499 projects, representing 451,340.4 MW (55.0 percent of the MW) withdrew prior to completion. Such projects may create barriers to entry for projects that would otherwise be completed, by taking up queue positions, increasing interconnection costs and creating uncertainty.
- In the first three months of 2023, 161.1 MW from the queue went in service. Of the 161.1 MW that went in service, 55.0 MW (34.1 percent) were combined cycle units, 55.0 MW (34.1 percent) were solar units and 51.1 MW (31.7 percent) were combustion turbine natural gas units.

1 Totals presented in this section include corrections to historical data and may not match totals presented in previous reports.
2 See PJM. Planning. "Generator Deactivations," (Accessed on March 31, 2023) <http://www.pjm.com/planning/services-requests/gen-deactivations.aspx>.
3 See PJM. Planning. "New Services Queue," (Accessed on March 31, 2023) <https://www.pjm.com/planning/services-requests/interconnection-queues.aspx>.
4 181 FERC ¶ 61,162 (2022).
5 See "Interconnection Process Reform," presented at April 27, 2022 meeting of the Members Committee. <https://www.pjm.com/-/media/committees-groups/committees/mc/2022/20220427/20220427-item-01a-1-interconnection-process-reform-presentation.ashx>.
6 The queue totals in this report are the winter net MW energy for the interconnection requests ("MW Energy") as shown in the queue.

- The number of queue entries increased during the past several years, primarily renewable projects. Of the 5,249 projects entered from January 2015 through March 2023, 3,915 projects (74.6 percent) were renewable. Of the 181 projects entered in the first three months of 2023, 164 projects (90.6 percent) were renewable. Renewable projects make up 76.3 percent of all projects in the queue and those projects account for 74.9 percent of the nameplate MW currently active, suspended or under construction in the queue as of March 31, 2023.

  But of the 215,812.0 MW of renewable projects in the queue, only 13,592.2 MW (6.3 percent) of capacity resources are expected to go into service, based on both historical completion rates and ELCC derate factors for battery, wind and solar.

Regional Transmission Expansion Plan (RTEP)

Market Efficiency Process

- There are significant issues with PJM's cost/benefit analysis that should be addressed prior to approval of additional projects. PJM's cost/benefit analysis does not correctly account for the costs of increased congestion associated with market efficiency projects.
- Through March 31, 2023, PJM has completed five market efficiency cycles under Order No. 1000.[7]

PJM MISO Interregional Market Efficiency Process (IMEP)

- PJM and MISO developed a process to facilitate the construction of interregional projects in response to the Commission's concerns about interregional coordination along the PJM-MISO seam. This process, called the Interregional Market Efficiency Process (IMEP), operates on a two year study schedule and is designed to address forward looking congestion.

  But the use of an inaccurate cost/benefit method by PJM and the correct method by MISO results in an over allocation of the costs associated with joint PJM/MISO projects to PJM participants and in some cases approval of projects that do not pass an accurate cost-benefit test.

PJM MISO Targeted Market Efficiency Process (TMEP)

- PJM and MISO developed the Targeted Market Efficiency Process (TMEP) to facilitate the resolution of historic congestion issues that could be addressed through small, quick implementation projects.

Supplemental Transmission Projects

- Supplemental projects are defined to be "transmission expansions or enhancements that are not required for compliance with PJM criteria and are not state public policy projects according to the PJM Operating Agreement. These projects are used as inputs to RTEP models, but are not required for reliability, economic efficiency or operational performance criteria, as determined by PJM."[8] Supplemental projects are exempt from competition.
- The average number of supplemental projects in each expected in service year increased by 975.0 percent, from 20 for years 1998 through 2007 (pre Order No. 890) to 215 for years 2008 through 2023 (post Order 890).[9]

End of Life Transmission Projects

- An end of life transmission project is a project submitted for the purpose of replacing existing infrastructure that is at, or is approaching, the end of its useful life. End of life transmission projects should be included in the RTEP process and should be subject to a transparent, robust and clearly defined mechanism to permit competition to build the project. Under the current approach, end of life projects are exempt from competition.

7 See *Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities*, Order No. 1000, FERC Stats. & Regs. ¶ 31,323 (2011) (Order No. 1000), *order on reh'g*, Order No. 1000-A, 139 FERC ¶ 61,132 (2012).

8 See PJM. "Transmission Construction Status," (Accessed on March 31, 2023) <http://www.pjm.com/planning/rtep-upgrades-status/construct-status.aspx>.

9 See *Preventing Undue Discrimination and Preference in Transmission Service*, Order No. 890, 118 FERC ¶ 61,119, *order on reh'g*, Order No. 890-A, 121 FERC ¶ 61,297 (2007), *order on reh'g*, Order No. 890-B, 123 FERC ¶ 61,299 (2008), *order on reh'g*, Order No. 890-C, 126 FERC ¶ 61,228, *order on clarification*, Order No. 890-D, 129 FERC ¶ 61,126 (2009).

Board Authorized Transmission Upgrades

- The Transmission Expansion Advisory Committee (TEAC) reviews proposals to improve transmission reliability in PJM and between PJM and neighboring regions. These proposals, which include reliability baseline, network, market efficiency and targeted market efficiency projects, as well as scope changes and project cancellations, but exclude supplemental and end of life projects, are periodically presented to the PJM Board of Managers for authorization.[10] In the first three months of 2023, the PJM Board approved $645.2 million in upgrades. As of March 31, 2023, the PJM Board has approved $42.2 billion in system enhancements since 1999.

Transmission Competition

- The MMU makes several recommendations related to the competitive transmission planning process. The recommendations include improved process transparency, incorporation of competition between transmission and generation alternatives and the removal of barriers to competition from nonincumbent transmission. These recommendations would help ensure that the process is an open and transparent process that results in the most competitive solutions.
- On May 24, 2018, the PJM Markets and Reliability Committee (MRC) approved a motion that required PJM, with input from the MMU, to develop a comparative framework to evaluate the quality and effectiveness of competitive transmission proposals with binding cost containment proposals compared to proposals from incumbent and nonincumbent transmission companies without cost containment provisions.

Qualifying Transmission Upgrades (QTU)

- A Qualifying Transmission Upgrade (QTU) is an upgrade to the transmission system that increases the Capacity Emergency Transfer Limit (CETL) into an LDA and can be offered into capacity auctions as capacity. Once a QTU is in service, the upgrade is eligible to continue to offer the approved incremental import capability into future RPM Auctions. As of March 31, 2023, no QTUs have cleared a Base Residual Auction or an Incremental Auction.

Transmission Facility Outages

- PJM maintains a list of reportable transmission facilities. When the reportable transmission facilities need to be taken out of service, PJM transmission owners are required to report planned transmission facility outages as early as possible. PJM processes the transmission facility outage requests according to rules in PJM's Manual 3 to decide if the outage is on time or late and whether or not they will allow the outage.[11]
- There were 15,651 transmission outage requests submitted in the first ten months of the 2022/2023 planning period. Of the requested outages, 76.4 percent were planned for less than or equal to five days and 9.1 percent were planned for greater than 30 days. Of the requested outages, 39.2 percent were late according to the rules in PJM's Manual 3.

Recommendations

Generation Retirements

- The MMU recommends that the question of whether Capacity Interconnection Rights (CIRs) should persist after the retirement of a unit be addressed. The rules need to ensure that incumbents cannot exploit control of CIRs to block or postpone entry of competitors.[12] (Priority: Medium. First reported 2013. Status: Partially adopted, 2012.)

Generation Queue

- Given the significance of data to market participants and regulators, the MMU recommends that all queue data and supplemental, network and baseline project data, including projected in service dates and estimated and final costs, be regularly updated with accurate and verifiable data. (Priority: High. New recommendation. Not adopted.)

10 Supplemental Projects, including the end of life subset of supplemental projects, do not require PJM Board of Managers authorization.

11 See "PJM Manual 03: Transmission Operations," Rev. 63 (November 16, 2022).

12 See Comments of the Independent Market Monitor for PJM, Docket No. ER12-1177-000 (March 12, 2012) <http://www.monitoringanalytics.com/Filings/2012/IMM_Comments_ER12-1177-000_20120312.PDF>.

- The MMU recommends that barriers to entry be addressed in a timely manner in order to help ensure that the capacity market will result in the entry of new capacity to meet the needs of PJM market participants. (Priority: Low. First reported 2012. Status: Not adopted.)
- The MMU recommends improvements in queue management including that PJM establish a review process to ensure that projects are removed from the queue if they are not viable, as well as a process to allow commercially viable projects to advance in the queue ahead of projects which have failed to make progress, subject to rules to prevent gaming.[13] (Priority: Medium. First reported 2013. Status: Partially adopted.)
- The MMU recommends continuing analysis of the study phase of PJM's transmission planning to reduce the need for postponements of study results, to decrease study completion times, and to improve the likelihood that a project at a given phase in the study process will successfully go into service.[14] (Priority: Medium. First reported 2014. Status: Partially adopted.)
- The MMU recommends outsourcing interconnection studies to an independent party to avoid potential conflicts of interest. Currently, these studies are performed by incumbent transmission owners under PJM's direction. This creates potential conflicts of interest, particularly when transmission owners are vertically integrated and the owner of transmission also owns generation. (Priority: Low. First reported 2013. Status: Not adopted.)

Market Efficiency Process

- The MMU recommends that the market efficiency process be eliminated because it is not consistent with a competitive market design. (Priority: Medium. First reported 2019. Status: Not adopted.)
- The MMU recommends that, if the market efficiency process is retained, PJM modify the rules governing cost/benefit analysis, the evaluation process for selecting among competing market efficiency projects and cost allocation for economic projects in order to ensure that all costs, including increased congestion costs and the risk of project cost increases, in all zones are included in order to ensure that the correct metrics are used for defining benefits. (Priority: Medium. First reported 2018. Status: Not adopted.)

Comparative Cost Framework

- The MMU recommends that PJM modify the project proposal templates to include data necessary to perform a detailed project lifetime financial analysis. The required data includes, but is not limited to: capital expenditure; capital structure; return on equity; cost of debt; tax assumptions; ongoing capital expenditures; ongoing maintenance; and expected life. (Priority: Medium. First reported 2020. Status: Not adopted.)

Transmission Competition

- The MMU recommends, to increase the role of competition, that the exemption of supplemental projects from the Order No. 1000 competitive process be terminated and that the basis for all such exemptions be reviewed and modified to ensure that the supplemental project designation is not used to exempt transmission projects from a transparent, robust and clearly defined mechanism to permit competition to build such projects or to effectively replace the RTEP process. (Priority: Medium. First reported 2017. Status: Not adopted. Rejected by FERC.)[15]
- The MMU recommends, to increase the role of competition, that the exemption of end of life projects from the Order No. 1000 competitive process be terminated and that end of life transmission projects be included in the RTEP process and should be subject to a transparent, robust and clearly defined mechanism to permit competition to build such projects. (Priority: Medium. First reported 2019. Status: Not adopted. Rejected by FERC.)[16]

13 PJM Filing, FERC Docket No. ER22-2110-000 (June 14, 2022); 181 FERC ¶ 61,162 (2022).
14 Ibid.
15 The FERC accepted tariff provisions that exclude supplemental projects from competition in the RTEP. 162 FERC ¶ 61,129 (2018), *reh'g denied*, 164 FERC ¶ 61,217 (2018).
16 In recent decisions addressing competing proposals on end of life projects, the Commission accepted a transmission owner proposal excluding end of life projects from competition in the RTEP process, 172 FERC ¶ 61,136 (2020), *reh'g denied*, 173 FERC ¶ 61,225 (2020), and rejected a proposal from PJM stakeholders that would have included end of life projects in competition in the RTEP process, 173 FERC ¶ 61,242 (2020).

- The MMU recommends that PJM enhance the transparency and queue management process for nonincumbent transmission investment. Issues related to data access and complete explanations of cost impacts should be addressed. The goal should be to remove barriers to competition from nonincumbent transmission providers. (Priority: Medium. First reported 2015. Status: Not adopted.)
- The MMU recommends that PJM continue to incorporate the principle that the goal of transmission planning should be the incorporation of transmission investment decisions into market driven processes as much as possible. (Priority: Low. First reported 2001. Status: Not adopted.)
- The MMU recommends the creation of a mechanism to permit a direct comparison, or competition, between transmission and generation alternatives, including which alternative is less costly and who bears the risks associated with each alternative. (Priority: Low. First reported 2013. Status: Not adopted.)
- The MMU recommends that PJM establish fair terms of access to rights of way and property, such as at substations, in order to remove any barriers to entry and permit competition between incumbent transmission providers and nonincumbent transmission providers in the RTEP. (Priority: Medium. First reported 2014. Status: Not adopted.)
- The MMU recommends that rules be implemented to permit competition to provide financing for transmission projects. This competition could reduce the cost of capital for transmission projects and significantly reduce total costs to customers. (Priority: Low. First reported 2013. Status: Not adopted.)
- The MMU recommends that storage resources not be includable as transmission assets for any reason. (Priority: High. First reported 2020. Status: Not adopted.)

Cost Allocation

- The MMU recommends a comprehensive review of the ways in which the solution based dfax is implemented. The goal for such a process would be to ensure that the most rational and efficient approach to implementing the solution based dfax method is used in PJM. Such an approach should allocate costs consistent with benefits and appropriately calibrate the incentives for investment in new transmission capability. No replacement approach should be approved until all potential alternatives, including the status quo, are thoroughly reviewed. (Priority: Medium. First reported 2020. Status: Not adopted.)
- The MMU recommends changing the minimum distribution factor in the allocation from 0.01 to 0.00 and adding a threshold minimum usage impact on the line.[17] (Priority: Medium. First reported 2015. Status: Not adopted.)

Transmission Line Ratings

- The MMU recommends that all PJM transmission owners use the same methods to define line ratings and that all PJM transmission owners implement dynamic line ratings (DLR), subject to NERC standards and guidelines, subject to review by NERC, PJM and the MMU, and approval by FERC. (Priority: Medium. First reported 2019. Status: Not adopted.)

Transmission Facility Outages

- The MMU recommends that PJM reevaluate all transmission outage tickets as on time or late as if they were new requests when an outage is rescheduled, create options for late requests based on the reasons, and apply the modified rules for late submissions to any such outages. (Priority: Low. First reported 2014. Status: Not adopted.)
- The MMU recommends that PJM draft a clear definition of the congestion analysis required for transmission outage requests and associated triggers, including both the extent of overloaded facilities and the level of economic congestion, to include in Manual 3 after appropriate review. (Priority: Medium. First reported 2015. Status: Not adopted.)
- The MMU recommends that PJM create options for late requests based on the reasons, and modify the rules to reduce or eliminate the approval of late outage requests submitted or rescheduled after the FTR auction

17 See *2015 State of the Market Report for PJM*, Volume II, Section 12: Generation and Transmission Planning, at 463, Cost Allocation Issues.

bidding opening date, based on those options. (Priority: Low. First reported 2015. Status: Not adopted.)

- The MMU recommends that PJM not permit transmission owners to divide long duration outages into smaller segments to avoid complying with the requirements for long duration outages. (Priority: Low. First reported 2015. Status: Not adopted.)

Conclusion

The goal of the PJM market design should be to enhance competition and to ensure that competition is the core element of all PJM markets. But transmission investments have not been fully incorporated into competitive markets. The construction of new transmission facilities has significant impacts on the energy and capacity markets. But when generating units retire or load increases, there is no market mechanism in place that would require or even permit direct competition between transmission and generation to meet loads in the affected area. In addition, despite FERC Order No. 1000, there is not yet a transparent, robust and clearly defined mechanism to permit competition to build transmission projects, to ensure that competitors provide a total project cost cap, or to obtain least cost financing through the capital markets.

The MMU recognizes that the Commission has issued orders that are inconsistent with the recommendations of the MMU and that PJM cannot unilaterally modify those directives. It remains the recommendation of the MMU that the PJM rules for competitive transmission development through the RTEP should build upon FERC Order No. 1000 to create real competition between incumbent transmission providers and nonincumbent transmission providers. The ability of transmission owners to block competition for supplemental projects and end of life projects and the reasons for that policy should be reevaluated. PJM should enhance the transparency and queue management process for nonincumbent transmission investment. Issues related to data access and complete explanations of cost impacts should be addressed. The goal should be to remove barriers to competition from nonincumbent transmission.

Another element of opening competition would be to consider transmission owners' ownership of property and rights of way at or around transmission substations. In many cases, the land acquired included property intended to support future expansion of the grid. Incumbents have included the costs of the property in their rate base, paid for by customers. PJM now has the responsibility for planning the development of the grid under its RTEP process. Property bought to facilitate future expansion should be a part of the RTEP process and be made available to all providers on equal terms.

The process for determining the reasonableness or purpose of supplemental transmission projects that are asserted to be not needed for reliability, economic efficiency or operational performance as defined under the RTEP process needs additional oversight and transparency. If there is a need for a supplemental project, that need should be clearly defined and there should be a transparent, robust and clearly defined mechanism to permit competition to build the project. If there is no defined need for of a supplemental project for reliability, economic efficiency or operational performance then the project should not be included in rates.

Managing the generation queues is a complex process. The PJM queue evaluation process will be significantly improved, based on the proposal submitted by PJM on June 14, 2022, and approved by FERC on November 29, 2022.[18] [19] The new rules include significant modifications to the interconnection process designed to address some of the key underlying issues and significantly improve the efficiency of the process. These modifications include process efficiency enhancements, recognition of project clusters affecting the same transmission facilities, incentives to reduce the entry of speculative projects in the queue, and incentives to remove projects that are not expected to reach commercial operation. The proposed solution should help to reduce backlog and to remove projects that are not viable earlier to help improve the overall efficiency of the queue process.

The impact of the modifications to the queue process will need to be evaluated to determine if they successfully remove projects from the queue if they are not viable, and allow commercially viable projects to advance in the queue

18 See *PJM*, Docket No. ER22-2110 (June 14, 2022).
19 181 FERC ¶ 61,162 (2022).

ahead of projects which have failed to make progress. The behavior of project developers also creates issues with queue management. When developers put multiple projects in the queue to maintain their own optionality while planning to build only one they also affect all the projects that follow them in the queue. Project developers may also enter speculative projects in the queue and then put the project in suspended status while they address financing. The impacts of such behavior and the incentives for such behavior are addressed in the new process which includes nonrefundable fees, credit requirements, enhanced site control, elimination of the ability to suspend a project and milestone requirements. The impact of these aspects of the revised interconnection process should continue to be evaluated to ensure that they are having the desired effect on project developer behavior. The PJM queue evaluation process should continue to be improved to help ensure that barriers to competition for new generation investments are not created. Issues that need to be addressed include the ownership rights to CIRs and whether transmission owners should perform interconnection studies.

The roles and efficiency of PJM, TOs and developers in the queue process all need to be examined and enhanced in order to help ensure that the queue process can function effectively and efficiently as the gateway to competition in the energy and capacity markets and not as a barrier to competition.

The Commission should require PJM, for example, to enhance the transparency and queue management process for nonincumbent transmission investment. Issues related to data access and complete explanations of cost impacts should be addressed. The goal should be to remove barriers to competition from nonincumbent transmission.

The addition of a planned transmission project changes the parameters of the capacity auction for the area, changes the amount of capacity needed in the area, changes the capacity market supply and demand fundamentals in the area and may effectively forestall the ability of generation to compete. But there is no mechanism to permit a direct comparison, let alone competition, between transmission and generation alternatives. There is no mechanism to evaluate whether the generation or transmission alternative is less costly, whether there is more risk associated with the generation or transmission alternatives, or who bears the risks associated with each alternative. Creating such a mechanism should be an explicit goal of PJM market design.

The current market efficiency process does exactly the opposite by permitting transmission projects to be approved without competition from generation. The broader issue is that the market efficiency project approach explicitly allows transmission projects to compete against future generation projects, but without allowing the generation projects to compete. Projecting speculative transmission related benefits for 15 years based on the existing generation fleet and existing patterns of congestion eliminates the potential for new generation to respond to market signals. The market efficiency process allows assets built under the cost of service regulatory paradigm to displace generation assets built under the competitive market paradigm. In addition, there are significant issues with PJM's current cost/benefit analysis which cause it to consistently overstate the potential benefits of market efficiency projects. The market efficiency process is misnamed. The MMU recommends that the market efficiency process be eliminated.

In addition, the use of an inaccurate cost-benefit method by PJM and the correct method by MISO results in an over allocation of the costs associated with joint PJM/MISO projects to PJM participants and in some cases approval of projects that do not pass an accurate cost-benefit test.

If it is retained, there are significant issues with PJM's cost/benefit analysis that should be addressed prior to approval of additional projects. The current cost/benefit analysis for a regional project, for example, explicitly and incorrectly ignores the increased congestion in zones that results from an RTEP project when calculating the energy market benefits. All costs should be included in all zones and LDAs. The definition of benefits should also be reevaluated.

The cost/benefit analysis should also account for the fact that the transmission project costs are not subject to cost caps and may exceed the estimated costs by a wide margin. When actual costs exceed estimated costs, the cost benefit analysis is effectively meaningless and low estimated costs may result in inappropriately favoring transmission projects over market generation projects.

The risk of cost increases for transmission projects should be incorporated in the cost benefit analysis.

There are currently no market incentives for transmission owners to plan, submit and complete transmission outages in a timely and efficient manner. Requiring transmission owners to pay does not create an effective incentive when those payments are passed through to transmission customers. The process for the submission of planned transmission outages needs to be carefully reviewed and redesigned to limit the ability of transmission owners to submit transmission outages that are late for FTR auction bid submission dates and are late for the day-ahead energy market and that have large and unnecessary impacts on the PJM energy market. The submission of late transmission outages can inappropriately affect market outcomes when market participants do not have the ability to modify market bids and offers. The PJM process for evaluating the congestion impact of transmission outages needs to be clearly defined and upgraded to provide for management of transmission outages to minimize market impacts. The MMU continues to recommend that PJM draft a clear and expanded definition of the congestion analysis required for transmission outage requests that is incorporated in the PJM Market Rules. PJM Manual 38 currently defines congestion resulting from a transmission outage as an overload on transmission facilities rather than using the general economic definition of congestion resulting from out of merit generation to control constraints. PJM does not currently evaluate the economic impact of congestion when reviewing proposed transmission outages.[20]

The treatment by PJM and Dominion Virginia Power of the outage for the Lanexa – Dunnsville Line illustrates some of the issues with the current process. The outage was submitted and delayed more than once. PJM's analysis of expected congestion did not highlight the magnitude of the issue. Dominion Virginia Power did not stage the outage so as to minimize market disruption and congestion until after there were significant disruptions and congestion.

As an example of the complexities of defining the benefits of transmission investments, the reduction in congestion is frequently and incorrectly cited as a metric of benefits.

20 PJM, "Manual 38: Operations Planning," Rev. 16 (Jan. 25, 2023), p20.

Congestion is frequently misunderstood. Congestion is not static. Congestion exhibits dynamic intertemporal variability and dynamic locational variability. More importantly, congestion is not the correct metric for evaluating the potential benefits of enhancing the transmission grid.

There is not a secular trend towards increasing congestion in PJM. Congestion is volatile on a monthly basis. Congestion is also volatile on an hourly and daily basis. For example, higher congestion can result from changes in seasonal and daily/hourly fuel costs.

The level and distribution of congestion at a point in time is a function of the location and size of generating units, the relative costs of the fuels burned and the associated marginal costs of generating units, the location and size of load and the locational capability of the transmission grid. Each of these factors changes over time.

The geographic distribution of congestion is dynamic. The nature and location of congestion in the PJM system has changed significantly over the last 10 years and continues to change. The nature and location of congestion in PJM can also change from one day to the next as a result of changes in relative fuel costs. As a result, building transmission to address a specific pattern of congestion does not make sense, unless the technology can be easily moved to new locations as conditions change. The transmission system is only one of many reasons that congestion exists. The dynamic nature of congestion and the multiple, interactive causes of congestion make it virtually impossible to identify the standalone impacts of an individual transmission investment on future congestion. It is possible, for example, that congestion occurring during a period of a few days in the winter as a result of very high fuel prices, significantly increases the reported level of congestion for the entire year. This has occurred in PJM. It would be a mistake to consider that level of congestion to be a signal to build transmission.

At a more fundamental level, congestion is not the correct metric for evaluating the potential benefits of enhancing the transmission grid. When there are binding transmission constraints and locational price differences, load pays more for energy than generation is paid to produce that energy.

The difference is congestion. Congestion is neither good nor bad, but is a direct measure of the extent to which there are multiple marginal generating units with different offers dispatched to serve load as a result of transmission constraints. Congestion occurs when available, least-cost energy cannot be delivered to all load because transmission facilities are not adequate to deliver that energy to one or more areas, and higher cost units in the constrained area(s) must be dispatched to meet the load. The result is that the price of energy in the constrained area(s) is higher than in the unconstrained area. Load in the constrained area pays the higher price for all energy including energy from low cost generation and energy from high cost generation, while only high cost generators are paid the high price at their bus and low cost generators are paid only the low price at their bus.

If FTRs worked perfectly and were assigned directly to load, FTRs would return all congestion to the load that paid the congestion. Congestion is not a cost, it is an accounting result of a market based on locational energy prices in which all load in a constrained area pays the higher single market clearing locational price, resulting in excess payments by load that are not paid to generation, which should be returned to load.

Counterintuitively, congestion actually increases when the transmission capacity between areas with lower cost generation and areas with higher cost generation increases but does not fully eliminate the need for some higher cost local generation. The smaller the amount of higher cost local generation needed to meet load, the more of the local load is met via low cost generation delivered over the transmission system and therefore the higher is the difference between what load pays and generation receives, congestion.

The PJM Regional Transmission Expansion Plan (RTEP) successfully addresses the need for transmission investment to reliably meet load. Together with the requirement that new generation pay interconnection costs, the RTEP process has resulted in the appropriate level of new transmission investment in PJM. There is no evidence that the PJM planning process is not adequate to meet the requirements of the PJM markets. Additional transmission investment is not a panacea. Transmission investment is expensive and long lived and it is essential that transmission investments be carefully planned for clearly identified needs in order to ensure that power markets can continue to provide reliable service at a competitive price.

Generation Interconnection Planning

Existing Generation Mix

Table 12-1 shows the existing PJM capacity by control zone and unit type.[21] As of March 31, 2023, PJM had an installed capacity of 198,657.1 MW, of which 44,329.4 MW (22.3 percent) are coal fired steam units, 56,278.2 MW (28.3 percent) are combined cycle units and 33,452.6 MW (16.8 percent) are nuclear units. This measure of installed capacity differs from capacity market installed capacity because it includes energy only units, external units and uses nameplate values for solar and wind resources.

The AEP Zone has the most installed capacity of any PJM zone. Of the 198,657.1 MW of PJM installed capacity, 35,544.6 MW (17.9 percent) are in the AEP Zone, of which 13,463.0 MW (37.9 percent) are coal fired steam units, 10,494.0 MW (29.5 percent) are combined cycle units and 2,071.0 MW (5.8 percent) are nuclear units.

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

Table 12-1 Existing capacity: March 31, 2023 (By zone and unit type (MW))[22]

Zone	Battery	Combined Cycle	CT - Natural Gas	CT - Oil	CT - Other	Fuel Cell	Hydro - Pumped Storage	Hydro - Run of River	Nuclear	RICE - Natural Gas	RICE - Oil	RICE - Other	Solar	Solar + Storage	Solar + Wind	Steam - Coal	Steam - Natural Gas	Steam - Oil	Steam - Other	Wind	Wind + Storage	Total
ACEC	0.0	781.6	544.7	0.0	0.0	1.6	0.0	0.0	0.0	0.0	4.0	4.0	67.1	0.0	0.0	0.0	0.0	0.0	0.0	7.5	0.0	1,410.4
AEP	4.0	10,494.0	4,108.2	16.2	4.8	0.0	66.0	420.9	2,071.0	0.0	0.0	20.4	637.2	0.0	0.0	13,463.0	738.0	0.0	0.0	3,500.9	0.0	35,544.6
AMPT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
APS	80.4	2,843.7	1,223.3	0.0	2.0	0.0	0.0	129.2	0.0	29.6	0.0	18.3	134.3	0.0	0.0	5,299.0	0.0	0.0	0.0	985.1	0.0	10,744.9
ATSI	0.0	4,647.5	958.0	608.0	6.4	0.0	0.0	0.0	2,134.0	0.0	18.5	24.8	0.0	0.0	0.0	1,490.0	325.0	0.0	136.0	0.0	0.0	10,348.2
BGE	1.0	0.0	267.6	228.8	0.0	0.0	0.0	0.0	1,716.0	0.0	0.0	4.2	1.1	0.0	0.0	1,578.0	143.5	397.0	57.0	0.0	0.0	4,394.2
COMED	109.0	3,471.1	6,673.3	226.2	0.0	0.0	0.0	0.0	10,473.5	0.0	0.0	15.0	9.0	0.0	0.0	2,646.0	1,326.0	0.0	0.0	5,031.0	0.0	29,980.1
DAY	0.0	0.0	897.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	34.0	0.0	36.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	967.6
DUKE	18.0	522.2	598.0	56.0	0.0	0.0	0.0	112.0	0.0	0.0	0.0	4.8	200.0	0.0	0.0	1,252.0	47.0	0.0	0.0	0.0	0.0	2,810.0
DUQ	0.0	306.0	0.0	15.0	0.0	0.0	0.0	6.3	1,777.0	14.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2,118.7
DOM	0.0	9,138.0	3,835.3	256.4	10.0	0.0	3,003.0	586.3	3,581.3	0.0	39.0	106.4	3,304.5	0.0	0.0	3,479.2	55.0	800.0	368.4	587.0	0.0	29,149.8
DPL	0.0	1,742.5	978.2	478.2	0.0	30.0	0.0	0.0	0.0	0.0	88.0	14.1	412.2	0.0	0.0	410.0	710.0	153.0	70.0	0.0	0.0	5,086.2
EKPC	0.0	0.0	774.0	0.0	0.0	0.0	0.0	136.0	0.0	0.0	0.0	0.0	50.0	0.0	0.0	1,687.0	0.0	0.0	0.0	0.0	0.0	2,647.0
JCPLC	40.0	2,229.5	531.1	225.6	0.0	0.4	140.0	0.0	0.0	0.0	0.0	14.1	416.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	3,596.9
MEC	0.0	2,595.0	2.0	398.5	0.0	0.0	0.0	19.0	0.0	0.0	0.0	30.9	0.0	0.0	0.0	80.0	35.0	0.0	60.0	0.0	0.0	3,220.4
OVEC	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2,388.8	0.0	0.0	0.0	0.0	0.0	2,388.8
PECO	0.0	4,089.0	0.0	828.0	0.0	0.0	1,070.0	572.0	4,546.8	0.0	2.0	0.9	3.0	0.0	0.0	0.0	765.3	0.0	103.0	0.0	0.0	11,980.0
PE	28.4	1,900.0	350.5	57.0	0.0	0.0	513.0	77.8	0.0	120.1	28.0	17.8	53.5	0.0	0.0	6,053.5	610.0	0.0	42.0	1,100.4	0.0	10,952.0
PEPCO	0.0	1,736.5	764.2	258.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	8.7	2.5	0.0	0.0	0.0	1,164.1	0.0	52.0	0.0	0.0	3,986.0
PPL	20.0	5,558.5	286.6	36.0	20.6	0.0	0.0	706.6	2,520.0	12.0	5.0	14.7	35.0	0.0	0.0	2,547.9	2,449.0	0.0	29.0	216.5	0.0	14,457.4
PSEG	7.7	4,223.1	958.2	0.0	0.0	0.0	0.0	5.0	3,493.0	0.0	0.0	9.0	230.3	0.0	0.0	0.0	3.0	0.0	179.1	0.0	0.0	9,108.3
XIC	0.0	0.0	670.6	0.0	0.0	0.0	0.0	0.0	1,140.0	0.0	0.0	0.0	0.0	0.0	0.0	1,955.0	0.0	0.0	0.0	0.0	0.0	3,765.6
Total	308.5	56,278.2	24,421.3	3,687.9	43.8	32.0	4,792.0	2,771.1	33,452.6	176.1	218.5	308.0	5,591.9	0.0	0.0	44,329.4	8,370.9	1,350.0	1,096.5	11,428.4	0.0	198,657.1

22 The capacity described in this section refers to all capacity in PJM at the summer installed capacity rating, regardless of whether the capacity entered the RPM Auction.

Table 12-2 shows the installed capacity by state for each fuel type. Pennsylvania has the most installed capacity of any PJM state. Of the 198,657.1 MW of installed capacity, 48,233.9 MW (24.3 percent) are in Pennsylvania, of which 8,681.4 MW (18.0 percent) are coal fired steam units, 18,292.2 MW (37.9 percent) are combined cycle units and 8,843.8 MW (18.3 percent) are nuclear units.

Table 12-2 Existing capacity: March 31, 2023 (By state and unit type (MW))

State	Battery	Combined Cycle	CT - Natural Gas	CT - Oil	CT - Other	Fuel Cell	Hydro - Pumped Storage	Hydro - Run of River	Nuclear	RICE - Natural Gas	RICE - Oil	RICE - Other	Solar	Solar + Storage	Solar + Wind	Steam - Coal	Steam - Natural Gas	Steam - Oil	Steam - Other	Wind	Wind + Storage	Total
DC	0.0	19.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	19.5
DE	0.0	742.5	325.5	116.3	0.0	30.0	0.0	0.0	0.0	0.0	0.0	8.1	50.0	0.0	0.0	410.0	710.0	0.0	70.0	0.0	0.0	2,462.4
IL	109.0	3,471.1	6,673.3	226.2	0.0	0.0	0.0	0.0	10,473.5	0.0	0.0	15.0	9.0	0.0	0.0	2,646.0	1,326.0	0.0	0.0	5,031.0	0.0	29,980.1
IN	0.0	1,835.0	441.4	0.0	0.0	0.0	0.0	8.2	0.0	0.0	0.0	3.2	282.6	0.0	0.0	3,923.8	0.0	0.0	0.0	2,353.2	0.0	8,847.4
KY	0.0	0.0	1,618.1	0.0	0.0	0.0	0.0	136.0	0.0	0.0	0.0	0.0	50.0	0.0	0.0	1,687.0	278.0	0.0	0.0	0.0	0.0	3,769.1
MD	21.0	2,717.0	1,684.5	502.7	0.0	0.0	0.0	0.0	1,716.0	0.0	76.0	18.9	385.1	0.0	0.0	1,758.0	1,307.6	550.0	109.0	295.0	0.0	11,140.8
MI	0.0	2,194.0	0.0	0.0	4.8	0.0	0.0	11.8	2,071.0	0.0	0.0	3.2	4.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	4,289.4
NC	0.0	165.0	0.0	0.0	0.0	0.0	0.0	315.0	0.0	0.0	18.0	0.0	1,006.5	0.0	0.0	0.0	0.0	0.0	0.0	208.0	0.0	1,712.5
NJ	47.7	7,234.2	2,034.0	225.6	0.0	2.0	140.0	5.0	3,493.0	0.0	4.0	27.1	713.5	0.0	0.0	0.0	3.0	0.0	179.1	7.5	0.0	14,115.6
OH	22.0	10,634.7	4,201.2	680.2	6.4	0.0	0.0	200.0	2,134.0	0.0	47.0	29.6	386.1	0.0	0.0	8,310.0	47.0	0.0	136.0	1,147.7	0.0	27,981.9
PA	49.9	18,292.2	1,526.5	1,334.5	20.6	0.0	1,583.0	1,445.7	8,843.8	176.1	40.5	82.6	156.5	0.0	0.0	8,681.4	4,184.3	0.0	234.0	1,582.3	0.0	48,233.9
TN	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
VA	0.0	8,973.0	4,172.3	591.4	12.0	0.0	3,069.0	460.1	3,581.3	0.0	33.0	112.4	2,528.0	0.0	0.0	2,474.2	515.0	800.0	368.4	12.0	0.0	27,702.1
WV	58.9	0.0	1,073.9	11.0	0.0	0.0	0.0	189.3	0.0	0.0	0.0	8.0	20.0	0.0	0.0	12,484.0	0.0	0.0	0.0	791.7	0.0	14,636.8
XIC	0.0	0.0	670.6	0.0	0.0	0.0	0.0	0.0	1,140.0	0.0	0.0	0.0	0.0	0.0	0.0	1,955.0	0.0	0.0	0.0	0.0	0.0	3,765.6
Total	308.5	56,278.2	24,421.3	3,687.9	43.8	32.0	4,792.0	2,771.1	33,452.6	176.1	218.5	308.0	5,591.9	0.0	0.0	44,329.4	8,370.9	1,350.0	1,096.5	11,428.4	0.0	198,657.1

Table 12-3 and Figure 12-1 show the age of existing PJM generators, by unit type, as of March 31, 2023. Of the 198,657.1 MW of installed capacity, 71,676.3 MW (36.1 percent) are from units older than 40 years, of which 34,642.3 MW (48.3 percent) are coal fired steam units, 191.0 MW (0.3 percent) are combined cycle units and 19,720.6 MW (27.5 percent) are nuclear units.

Table 12-3 Capacity (MW) by unit type and age (years): March 31, 2023

Age (years)	Battery	Combined Cycle	CT - Natural Gas	CT - Oil	CT - Other	Fuel Cell	Hydro - Pumped Storage	Hydro - Run of River	Nuclear	RICE - Natural Gas	RICE - Oil	RICE - Other	Solar	Solar + Storage	Solar + Wind	Steam - Coal	Steam - Natural Gas	Steam - Oil	Steam - Other	Wind	Wind + Storage	Total
Less than 20	308.5	45,914.2	5,015.3	0.0	43.8	32.0	0.0	293.6	0.0	164.1	20.0	210.8	5,591.9	0.0	0.0	3,475.0	82.0	0.0	47.4	11,338.4	0.0	72,537.0
20 to 40	0.0	10,173.0	18,901.7	960.0	0.0	0.0	3,003.0	318.4	13,732.0	12.0	25.0	97.2	0.0	0.0	0.0	6,212.1	76.3	0.0	843.1	90.0	0.0	54,443.8
40 to 60	0.0	191.0	504.3	2,727.9	0.0	0.0	1,789.0	232.0	19,720.6	0.0	173.5	0.0	0.0	0.0	0.0	31,940.5	6,173.1	1,350.0	0.0	0.0	0.0	64,801.9
Greater than 60	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1,927.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2,701.8	2,039.5	0.0	206.0	0.0	0.0	6,874.4
Total	308.5	56,278.2	24,421.3	3,687.9	43.8	32.0	4,792.0	2,771.1	33,452.6	176.1	218.5	308.0	5,591.9	0.0	0.0	44,329.4	8,370.9	1,350.0	1,096.5	11,428.4	0.0	198,657.1

Figure 12-1 Capacity (MW) by age (years): March 31, 2023

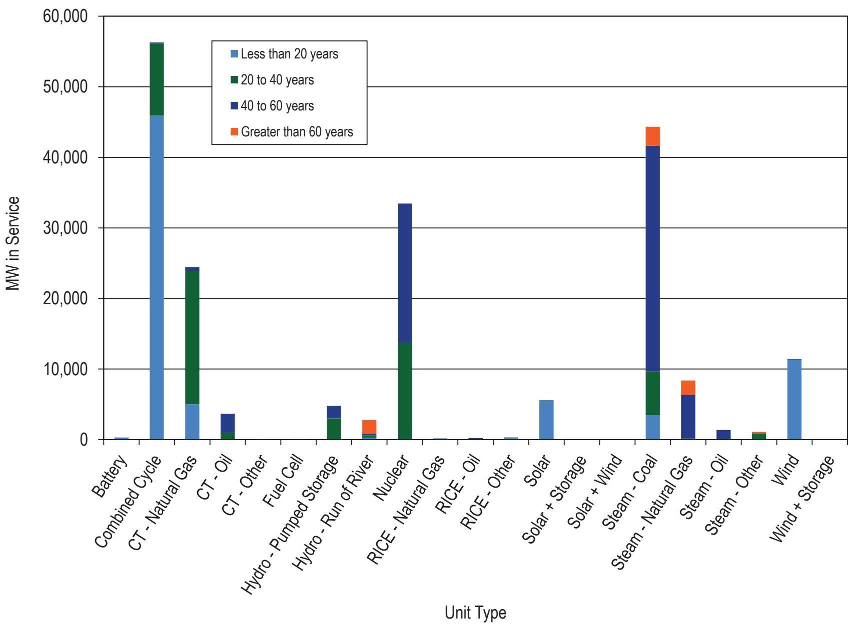


Figure 12-2 is a map of units, less than 20 MW in size that came online between January 1, 2011, and March 31, 2023. A mapping to these unit names is in Table 12-4.

Figure 12-2 Map of unit additions (less than 20 MW): January 1, 2011 through March 31, 2023

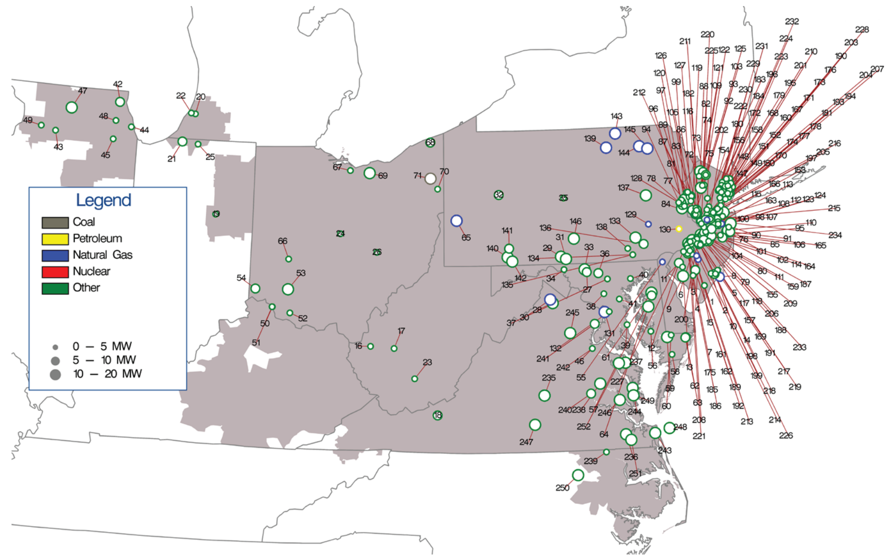


Table 12-4 Unit identification for map of unit additions (less than 20 MW): January 1, 2011 through March 31, 2023

ID	Unit	ID	Unit	ID	Unit	ID	Unit	ID	Unit
1	ACE CAPE MAY COUNTY 1 LF	56	DPL BUCKTOWN 1 SP	111	JC NORTH HANOVER 4 SP	166	PS DEVILSBROOK 1 SP	221	PS RIVER ROAD 2 SP
2	ACE CATES ROAD 2 SP	57	DPL CHURCH HILL 1 SP	112	JC NORTH PARK 1 SP	167	PS DOREMUS SOLAR 1 SP	222	PS ROSELAND SOLAR 1 SP
3	ACE CEDAR BRANCH 1 SP	58	DPL COSTEN 1 SP	113	JC NORTH PARK 2 SP	168	PS E RUTHERFORD SOLAR 1 SP	223	PS SADDLE BROOK SOLAR 1 SP
4	ACE EGG HARBOR-KELLOGG 1 FC	59	DPL HEBRON 1 SP	114	JC NORTH RUN 11 SP	169	PS EASTAMPTON 1 SP	224	PS SPRINGFIELD SOLAR 1 SP
5	ACE GALLOWAY LANDFILL 2 SP	60	DPL KUMQUAT 1 SP	115	JC OLD BRIDGE 1 SP	170	PS EDISON 1 SP	225	PS SUNNYMEADE SOLAR 1 SP
6	ACE GEMS LANDFILL 1 SP	61	DPL PONDTOWN 1 SP	116	JC PAUCH 3 SP	171	PS ESSEX 105 CT	226	PS TAYLORS LANE 1 SP
7	ACE MAYS LANDING 1 SP	62	DPL WORCESTER NORTH 1 SP	117	JC PEMBERTON 1 SP	172	PS FAIRLAWN SOLAR 1 SP	227	PS THOROFARE SOLAR 2 SP
8	ACE MIDTOWN THERMAL 2 CT	63	DPL WORCESTER SOUTH 2 SP	118	JC PEMBERTON 2 SP	173	PS FOODBANK 1 SP	228	PS TURNPIKE 1 SP
9	ACE OAK FAIRTON 1 SP	64	DPL WYE MILLS 1 SP	119	JC QUAKERTOWN 9 SP	174	PS FORTY NINTH SOLAR 1 SP	229	PS W CALDWELL SOLAR 1 SP
10	ACE PEAR STREET 1 SP	65	DUQ PIT MICROGRID 1 CT	120	JC RICHLINE 3 SP	175	PS GLOUCESTER SOLAR 1 SP	230	PS W CALDWELL SOLAR 2 SP
11	ACE PILESGROVE 1 SP	66	FE DOVETAIL 1 CT	121	JC RINGOES 1 SP	176	PS HACKENSACK 1 SP	231	PS WALDWICK SOLAR 1 SP
12	ACE PILESGROVE 2 SP	67	FE ERIE COUNTY 1 LF	122	JC SUSSEX 1 LF	177	PS HIGHLAND PARK 3 BT	232	PS WEST ORANGE SOLAR 1 SP
13	ACE PITTSGROVE 1 SP	68	FE GENEVA 1 LF	123	JC TINTON FALLS 3 SP	178	PS HIGHLAND PARK 4 SP	233	PS WEST PEMBERTON 1 SP
14	ACE SEASHORE 1 SP	69	FE LORAIN 1 LF	124	JC UPPER FREEHOLD 1 SP	179	PS HILLSDALE SOLAR 1 SP	234	PS WEST WINDSOR 1 CT
15	ACE TANSBORO ROAD 1 FC	70	FE MAHONING 1 LF	125	JC WANTAGE 2 SP	180	PS HINCHMANS SOLAR 1 SP	235	VP BUCKINGHAM 1 SP
16	AEP BALLS GAP 1 BT	71	FE WARREN-EVERGREEN 1 CT	126	JC WARREN 1 SP	181	PS HOBOKEN SOLAR 2 SP	236	VP GARDNER FARMS 1 SP
17	AEP CHARLESTON 1 LF	72	JC AUGUSTA 1 SP	127	JC WASHBURN AVE 4 SP	182	PS HOPEWELL 1 SP	237	VP GARDYS MILL ROAD 5 SP
18	AEP CLOYDS MT 1 LF	73	JC BEAVER RUN 3 SP	128	ME GLENDON 1 LF	183	PS HOPEWELL 2 BT	238	VP HOLLYFIELD 1 SP
19	AEP DEERCREEK 1 SP	74	JC BERKSHIRE 2 SP	129	ME READING HOSPITAL 1 CT	184	PS JACKSON SOLAR 1 SP	239	VP MURPHY 1 SP
20	AEP EAST WATERVLIET 1 SP	75	JC BERNARDS TOWNSHIP 1 SP	130	PE MORRIS ROAD 1 D	185	PS KINSLEY BEAVER 2 SP	240	VP NORTHEAST 2 LF
21	AEP OLIVE 1 SP	76	JC BRICKYARD 4 SP	131	PEP CAPITAL POWER PLANT 1 CT	186	PS KINSLEY DEPTFORD 1 SP	241	VP OCCOQUAN 1 LF
22	AEP ORCHARD HILLS 1 LF	77	JC COPPER HILL 4 SP	132	PEP ROLLINS AVENUE 3 SP	187	PS KUSER SOLAR 1 SP	242	VP OCCOQUAN 2 LF
23	AEP RALEIGH COUNTY 1 LF	78	JC CYPHERS ROAD 5 SP	133	PL DART CONTAINER 1-2 LF	188	PS LANDFILL 5 SP	243	VP OCEANA 1 SP
24	AEP TRENT 1 BT	79	JC DIXSOLAR 51 SP	134	PL HOLTWOOD 11	189	PS LAWNSIDE 14 BT	244	VP PULLER 1 SP
25	AEP TWINBRANCH 1 SP	80	JC DIXSOLAR 52 SP	135	PL HOLTWOOD 13	190	PS LEONIA SOLAR 1 SP	245	VP REMINGTON 1 SP
26	AEP ZANESVILLE 2 LF	81	JC DOMIN LANE 1 SP	136	PL KEYSTONE 1 SP	191	PS LUMBERTON STACY HAINES 5 SP	246	VP ROCHAMBEAU 1 SP
27	AP BAKER POINT 1 SP	82	JC DURBAN AVENUE 1 SP	137	PL PA SOLAR 1 SP	192	PS MANTUA CREEK 7 BT	247	VP TWITTYS CREEK 1 SP
28	AP DOUBLE TOLLGATE SP	83	JC E FLEMINGTON 5 SP	138	PL TURKEY HILL 1 WF	193	PS MARION SOLAR 1 SP	248	VP VIRGINIA OFFSHORE 1 WF
29	AP ELK HILL 1 SP	84	JC EAST AMWELL 7 SP	139	PN ALPACA GLORY BARN 1 D	194	PS MATRIX PA SOLAR 2 SP	249	VP WAN - GLOUCESTER 1 SP
30	AP HP HOOD 1 CT	85	JC EGYPT 3 SP	140	PN GARRETT 1 BT	195	PS MAYWOOD SOLAR 1 SP	250	VP WHITAKERS 1 SP
31	AP LETZBURG - ELK HILL 2 SP	86	JC FISCHER 8 SP	141	PN LAUREL HIGHLANDS 2 LF	196	PS METRO HQ 2 SP	251	VP WHITE MARSH - SUFFOLK 1 SP
32	AP MAHONING CREEK 1 H	87	JC FOUL RIFT ROAD 1 SP	142	PN MEYERSDALE 2 BT	197	PS MIDDLESEX 1 SP	252	VP WOODBINE ROAD 1 SP
33	AP MT ST MARYS PV PARK 2 SP	88	JC FRANKFORD 4 SP	143	PN MILAN ENERGY 1 D	198	PS MILL CREEK 1 SP		
34	AP PINESBURG 1 SP	89	JC FRANKLIN 7 SP	144	PN NORTH MESHOPPEN 1 CT	199	PS MOORESTOWN 1 SP		
35	AP STATE COLLEGE 1 BT	90	JC FREEMALL 1 FC	145	PN OXBOW CREEK ENERGY CENTER 1 D	200	PS MT LAUREL 1 SP		
36	AP UNION BRIDGE 1 SP	91	JC FRENCHES 2 SP	146	PN WHITETAIL 1 SP	201	PS NEW MILFORD SOLAR 1 SP		
37	BC ALPHA RIDGE 1 LF	92	JC FRENCHTOWN 1 SP	147	PS ALDENE SOLAR 1 SP	202	PS NEW ROAD 1 SP		
38	BC BRIGHTON DAM 1 H	93	JC FRENCHTOWN 2 SP	148	PS ATHENIA SOLAR 1 SP	203	PS NEWARK SOLAR 1 SP		
39	BC CHESAPEAKE BEACH 1 BT	94	JC FRENCHTOWN 3 SP	149	PS BAYONNE 1 SP	204	PS NEWARK SOLAR 3 SP		
40	BC KINGSVILLE 1 SP	95	JC HANOVER 2 SP	150	PS BAYONNE SOLAR 2 SP	205	PS NIXON LANE 2 SP		
41	BC MILLERSVILLE 1 LF	96	JC HARMONY 1 SP	151	PS BELLEVILLE SOLAR 1 SP	206	PS NORTH AMERICAN 4 SP		
42	COM COUNTRYSIDE 1 LF	97	JC HIGH STREET 6 SP	152	PS BENNETTS SOLAR 1 SP	207	PS NORTH AVE SOLAR 1 SP		
43	COM DIXON LEE 5 LF	98	JC HOFFMAN STATION ROAD 2 SP	153	PS BLACK ROCK 1 SP	208	PS OWENS CORNING 1 SP		
44	COM GRAND RIDGE 6 BT	99	JC HOLLAND 4 SP	154	PS BRIDGEWATER SOLAR 2 SP	209	PS PARKLANDS 1 SP		
45	COM MAGID GLOVE 1 BT	100	JC HOLMDEL 9 SP	155	PS BUSTLETON 2 SP	210	PS PATERSON PLANK ROAD 1 SP		
46	COM MORRIS 1 LF	101	JC HOWELL 1 SP	156	PS CALDWELL PUMP 2 BT	211	PS PENNINGTON 3 BT		
47	COM ORCHARD 1 LF	102	JC JACOBSTOWN 1 SP	157	PS CAMPUS DRIVE 2 SP	212	PS PENNINGTON 4 SP		
48	COM SOLBERG 1 BT	103	JC JUNCTION ROAD 6 SP	158	PS CEDAR GROVE SOLAR 1 SP	213	PS PENNSAUKEN 1 LF		
49	COM STERLING RAIL 1 BT	104	JC LAKEHURST 3 SP	159	PS CEDAR LANE FLORENCE 6 SP	214	PS PENNSAUKEN 3 SP		
50	DEOK BECKJORD 1 BT	105	JC LEBANON 1 SP	160	PS COOK ROAD SOLAR 2 SP	215	PS PRINCETON HOSPITAL 1 CT		
51	DEOK BECKJORD 2 BT	106	JC LEGLER LANDFILL 7 SP	161	PS COOPER HOSPITAL 1 BT	216	PS RARITAN CENTER 3 SP		
52	DEOK BROWN COUNTY 1 LF	107	JC MANALAPAN 1 SP	162	PS COOPER HOSPITAL 15 SP	217	PS REEVES EAST 3 SP		
53	DEOK CLINTON 1 BT	108	JC MILLHURST 3 SP	163	PS CRANBURY 2 SP	218	PS REEVES SOUTH 1 SP		
54	DEOK WILLEY 1 BT	109	JC MOUNT OLIVE 3 SP	164	PS CROSSWIC 1 SP	219	PS REEVES WEST 4 SP		
55	DPL BLOOM ENERGY 1 FC	110	JC MUDDY FORGE 3 SP	165	PS CROSSWIC 2 SP	220	PS RIDER UNIVERSITY 3 SP		

Figure 12-3 is a map of units, 20 MW or greater in size, that came online between January 1, 2011 and March 31, 2023. A mapping to these unit names is in Table 12-5.

Figure 12-3 Map of unit additions (20 MW or greater): January 1, 2011 through March 31, 2023

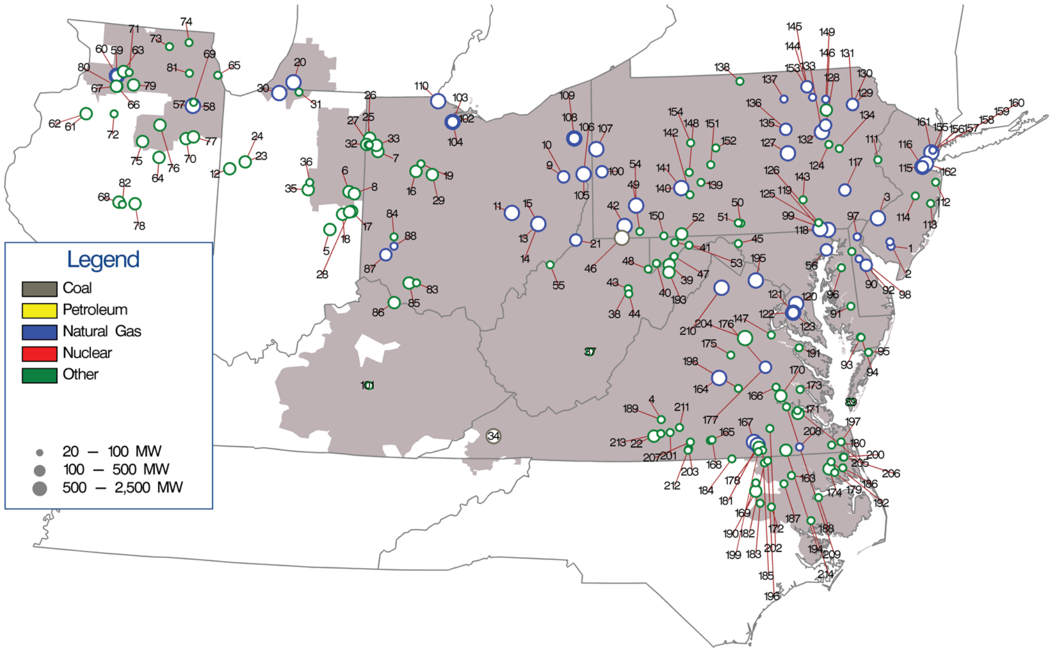


Table 12-5 Unit identification for map of unit additions (20 MW or greater): January 1, 2011 through March 31, 2023

ID	Unit	ID	Unit	ID	Unit	ID	Unit
1	ACE CLAYVILLE 1 CT	56	BC PERRYMAN 6 CT	111	JC EDGE ROAD 5 BT	166	VP BRIEL FARM 1 SP
2	ACE VINELAND 11 CT	57	COM 929 JACKSON 1 CC	112	JC HAMILTON ROAD 5 SP	167	VP BRUNSWICK 1CC
3	ACE WEST DEPTFORD CROWN POINT 1 CC	58	COM 929 JACKSON 2 CC	113	JC OAK RIDGE 3 SP	168	VP BUTCHER CREEK 1 SP
4	AEP ALTAVISTA 1 SP	59	COM 942 NELSON 1 CC	114	JC PLUMSTED ENERGY 6 BT	169	VP CHESTNUT 1 SP
5	AEP BELLFLOWER 1 SP	60	COM 942 NELSON 2 CC	115	JC WOODBRIDGE 1 CC	170	VP CHICKAHOMINY 1 SP
6	AEP BITTER RIDGE 1 WF	61	COM BISHOP HILL 1 WF	116	JC WOODBRIDGE 2 CC	171	VP COLONIAL TRAIL WEST 1 SP
7	AEP BLUE CREEK 3 WF	62	COM BISHOP HILL 2 WF	117	ME BIRDSBORO 1 CC	172	VP CONETOE 2 SP
8	AEP BLUFF POINT 2 WF	63	COM BLOOMING GROVE 1 WF1	118	PE DELTA 1-4 CC	173	VP CORRECTIONAL 1 SP
9	AEP CARROLL COUNTY 1 CC	64	COM BRIGHT STALK 1 WF	119	PE DELTA 5-7 CC	174	VP DESERT 1 WF
10	AEP CARROLL COUNTY 2 CC	65	COM GRAND RIDGE 7 BT	120	PEP KEYS ENERGY CENTER 1 CC	175	VP DESPER 1 SP
11	AEP DRESDEN 1 CC	66	COM GREEN RIVER 1 WF	121	PEP ST CHARLES - KELSON RIDGE 1 CC	176	VP DOSWELL 2 CT
12	AEP FOWLER RIDGE 4 WF	67	COM GREEN RIVER 2 WF	122	PEP ST CHARLES-KELSON RIDGE 1 CC	177	VP DOSWELL 3 CT
13	AEP GUERNSEY 11 CC	68	COM HILLTOPPER 1 WF	123	PEP ST CHARLES-KELSON RIDGE 2 CC	178	VP DRY BREAD 1 SP
14	AEP GUERNSEY 21 CC	69	COM JOLIET 1 BT	124	PL HAZEL 1 FW	179	VP ELIZABETH CITY 1 SP
15	AEP GUERNSEY 31 CC	70	COM KELLY CREEK 1 WF	125	PL HOLTWOOD 18	180	VP GRASSFIELD 1 SP
16	AEP HARDIN 2 SP	71	COM LEE DEKALB 3 BT	126	PL HOLTWOOD 19	181	VP GREENSVILLE 1 CC
17	AEP HEADWATERS 1 WF	72	COM LONE TREE 3 WF	127	PL HUMMEL STATION 1 CC	182	VP GUTENBERG - OCONECHE 1 SP
18	AEP HEADWATERS 2 WF	73	COM MARENGO 1 BT	128	PL HUNLOCK CC	183	VP HARTS MILL 1 SP
19	AEP HOG CREEK 1 WF	74	COM MCHENRY 1 BT	129	PL LACKAWANNA COUNTY 1 CC	184	VP HAWTREE CREEK 1 SP
20	AEP INDECK NILES ENERGY CENTER 1 CC	75	COM MINONK 1 WF	130	PL LACKAWANNA COUNTY 2 CC	185	VP IVORY LANE 1 SP
21	AEP LONG RIDGE ENERGY 1 CC	76	COM OTTER CREEK 1 WF	131	PL LACKAWANNA COUNTY 3 CC	186	VP IVY NECK 2 SP
22	AEP MAPLEWOOD 1 SP	77	COM PILOT HILL 1 WF	132	PL MOXIE FREEDOM 11 CC	187	VP KELFORD 1 SP
23	AEP MEADOW LAKE 5 WF	78	COM RADFORDS RUN 1 WF	133	PL MOXIE FREEDOM 21 CC	188	VP MACKEYS 1 SP
24	AEP MEADOW LAKE 6 WF	79	COM SHADY OAKS 1 WF	134	PL PA SOLAR 2 SP	189	VP MECHANICSVILLE 2 SP
25	AEP PAULDING 3 WF	80	COM WALNUT RIDGE 1 WF	135	PL PATRIOT 1 F	190	VP MOCCASIN CREEK - FERN 1 SP
26	AEP PAULDING 41 WF	81	COM WEST CHICAGO 3 BT	136	PL PATRIOT 2 F	191	VP MONTROSS 1 SP
27	AEP PAULDING 42 WF	82	COM WHITNEY HILL 2 WF	137	PN BEAVER DAM 1 D	192	VP MORGAN CORNER 1 SP
28	AEP RIVERSTART 1 SP	83	DAY HIGHLAND COUNTY 1 SP	138	PN BIG LEVEL 1 WF	193	VP NEW CREEK 1 WF
29	AEP SCIOTO RIDGE 1 WF	84	DAY TAIT 8 BT	139	PN CHESTNUT FLATS 1 WF	194	VP NEWSOMS 1 SP
30	AEP ST JOSEPH ENERGY CENTER 1 CC	85	DEOK HILLCREST 1 SP	140	PN FAIRVIEW 1 CC	195	VP PANDA STONEWALL 1 CC
31	AEP ST JOSEPH SOLAR PARK 1 SP	86	DEOK MELDAHL DAM 1 H	141	PN FAIRVIEW 2 CC	196	VP PECAN 1 SP
32	AEP TIMBER2 1 WF	87	DEOK MIDDLETOWN ENERGY 1 CC	142	PN HIGHLAND NORTH 2 WF	197	VP POCATY 1 SP
33	AEP TRISHE 1 WF	88	DEOK YANKEE 1 F	143	PN LAUREL HILLS 1 WF	198	VP POWHATAN 2 SP
34	AEP VIRGINIA CITY 1 F	89	DPL CHERRYDALE 1 SP	144	PN LIBERTY ASYLUM 10 F	199	VP PUMPKINSEED 1 SP
35	AEP WILDCAT 1A WF	90	DPL DEMEC - CLAYTON 2 CT	145	PN LIBERTY ASYLUM 20 F	200	VP RANCHLAND 2 SP
36	AEP WILDCAT 1B WF	91	DPL DORCHESTER COUNTY 1 SP	146	PN MEHOOPANY 1 WF	201	VP RENAN 1 SP
37	AP BEECH RIDGE 2 WF	92	DPL GARRISON EC 1 CC	147	PN MEHOOPANY 2 WF	202	VP SAPONY 1 SP
38	AP BEECH RIDGE 3 BT	93	DPL GREAT BAY KINGS CREEK 1 SP	148	PN PATTON 1 WF	203	VP SOUTH BOSTON 1 F
39	AP BLACK ROCK 1 WF	94	DPL GREAT BAY KINGS CREEK 2 SP	149	PN PGCOGEN 2 CT	204	VP SPOTSYLVANIA 1 SP
40	AP FAIR WIND 2 WF	95	DPL OAK HALL 1 SP	150	PN RINGER HILL 1 WF	205	VP SPRING GROVE 1 SP
41	AP FOURMILE RIDGE 1 WF	96	DPL PONDTOWN 2 SP	151	PN SANDY RIDGE 1 WF	206	VP SUMMIT FARMS 1 SP
42	AP GREENE COUNTY 1 CC	97	DPL RED LION 1 FC	152	PN SCHOOL HOUSE 1 SP	207	VP SUNNYBROOK FARM 1 SP
43	AP LAUREL MOUNTAIN 1 BT	98	DPL TOWNSEND 1 SP	153	PN SUGAR RUN 2 CT	208	VP UNION CAMP 9-10 F
44	AP LAUREL MOUNTAIN 1 WF	99	DPL WILDCAT POINT 1 CC	154	PN VIADUCT 1 SP	209	VP WARDS CREEK 1 SP
45	AP MARLOWE 1 SP	100	DUQ MONACA-PENNCHEM 1 CC	155	PS KEARNY 131 CT	210	VP WARREN COUNTY FRONT ROYAL CC
46	AP NORTH LONGVIEW 1 F	101	EKPC TURKEY CREEK 1 SP	156	PS KEARNY 132 CT	211	VP WATER STRIDER 1 SP
47	AP PINNACLE 1 WF	102	FE FREMONT 1 SCCT	157	PS KEARNY 133 CT	212	VP WATLINGTON 1 SP
48	AP ROTH ROCK 1 WF	103	FE FREMONT 2 SCCT	158	PS KEARNY 134 CT	213	VP WHITEHORN 1 SP
49	AP SOUTH CHESTNUT 1 WF	104	FE FREMONT ENERGY CENTER 3 CC	159	PS KEARNY 141 CT	214	VP WILKINSON ENERGY CENTER 1 SP
50	AP ST THOMAS 1 SP	105	FE HIBBETS MILLS ROAD 1 CC	160	PS KEARNY 142 CT		
51	AP ST THOMAS 2 SP	106	FE HIBBETS MILLS ROAD 2 CC	161	PS NEWARK ENERGY CENTER 10 CC		
52	AP TWIN RIDGES 1 WF	107	FE HICKORY RUN 1 CC	162	PS SEWAREN 7 CC		
53	AP WARRIOR RUN 2 BT	108	FE LORDSTOWN ENERGY CENTER 1 CC	163	VP AULANDER HOLLOMAN 1 SP		
54	AP WESTMORELAND 1 CC	109	FE LORDSTOWN ENERGY CENTER 2 CC	164	VP BEAR GARDEN		
55	AP WILLOW ISLAND 1 H	110	FE OREGON ENERGY CENTER 1 CC	165	VP BLUESTONE FARM 1 SP		

Generation Retirements[23] [24]

Generating units generally plan to retire when they are not economic and do not expect to be economic. The MMU performs an analysis of the economics of all units that plan to retire in order to verify that the units are not economic and there is no potential exercise of market power through physical withholding that could advantage the owner's portfolio.[25] The definition of economic is that unit net revenues are greater than or equal to the unit's avoidable or going forward costs.

PJM does not have the authority to order generating plants to continue operating. PJM's responsibility is to ensure system reliability. When a unit retirement creates reliability issues based on existing and planned generation facilities and on existing and planned transmission facilities, PJM identifies transmission solutions.[26]

Rules that preserve the Capacity Interconnection Rights (CIRs) associated with retired units, and with the conversion from Capacity Performance (CP) to energy only status, impose significant costs on new entrants. Currently, CIRs persist for one year if unused, and they can be further extended, at no cost, if assigned to a new project in the interconnection queue at the same point of interconnection.[27] There are currently no rules governing the retention of CIRs when units want to convert to energy only status or require time to upgrade to retain CP status. The rules governing conversion or upgrades should be the same as the rules governing retired units. Reforms that require the holders of CIRs to use or lose them, and/or impose costs to holding or transferring them, could make new entry appropriately more attractive. The economic and policy rationale for extending CIRs for inactive units is not clear. Incumbent providers receive a significant advantage simply by imposing on new entrants the entire cost of system upgrades needed to accommodate new entrants. The policy question of whether CIRs should persist after the retirement of a unit should be addressed. Even if the policy treatment of such CIRs remains unchanged, the rules need to ensure that incumbents cannot exploit control of CIRs to block or postpone entry of competitors.

In May 2012, PJM stakeholders (through the Interconnection Process Senior Task Force (IPSTF)) modified the rules to reduce the length of time for which CIRs are retained by the current owner after unit retirements from three years to one.[28] The MMU recognized the progress made in this rule change, but it did not fully address the issues. The MMU recommends that the question of whether CIRs should persist after the retirement of a unit, or conversion from CP to energy only status, be addressed. The rules need to ensure that incumbents cannot exploit control of CIRs to block or postpone entry of competitors.[29]

A new dimension to the CIR issue has emerged as a result of the fact that intermittent and storage resources do not have a must offer obligation in the capacity market like the must offer requirement for the majority of capacity resources. In the absence of a uniform must offer requirement in the capacity market, those intermittent resources that hold CIRs but do not offer in the capacity market are effectively blocking entry of competitors who would offer in the capacity market.

23 See PJM. Planning. "Generator Deactivations," (Accessed on March 31, 2023) <http://www.pjm.com/planning/services-requests/gen-deactivations.aspx>.
24 Generation retirements reported in this section do not include external units. Therefore, retirement totals reported in this section may not match totals reported elsewhere in this report where external units are included.
25 See OATT Part V and Attachment M–Appendix § IV.
26 See PJM. "*Explaining Power Plant Retirements in PJM*," at <http://learn.pjm.com/three-priorities/planning-for-the-future/explaining-power-plant-retirements.aspx>.
27 See OATT § 230.3.3.
28 See PJM Interconnection, L.L.C., Docket No. ER12-1177 (Feb. 29, 2012).
29 See Comments of the Independent Market Monitor for PJM, Docket No. ER12-1177-000 (March 12, 2012) <http://www.monitoringanalytics.com/Filings/2012/IMM_Comments_ER12-1177-000_20120312.PDF>.

Generation Retirements 2011 through 2026

Table 12-6 shows that as of March 31, 2023, there are 54,355.9 MW of generation that have been, or are planned to be, retired between 2011 and 2026, of which 40,623.8 MW (74.7 percent) are coal fired steam units. Retirements are primarily a result of the inability of coal and other units to compete with efficient combined cycle units burning low cost gas.

Table 12-6 Summary of unit retirements by unit type (MW): 2011 through 2026

	Battery	Combined Cycle	CT - Natural Gas	CT - Oil	CT - Other	Fuel Cell	Hydro - Pumped Storage	Hydro - Run of River	Nuclear	RICE - Natural Gas	RICE - Oil	RICE - Other	Solar	Solar + Storage	Solar + Wind	Steam - Coal	Steam - Natural Gas	Steam - Oil	Steam - Other	Wind	Wind + Storage	Total
Retirements 2011	0.0	0.0	0.0	128.3	0.0	0.0	0.0	0.0	0.0	0.0	2.7	0.0	0.0	0.0	0.0	543.0	522.5	0.0	0.0	0.0	0.0	1,196.5
Retirements 2012	0.0	0.0	250.0	240.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	5,907.9	0.0	548.0	16.0	0.0	0.0	6,961.9
Retirements 2013	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	5.9	7.0	0.0	0.0	0.0	2,589.9	82.0	166.0	8.0	0.0	0.0	2,858.8
Retirements 2014	0.0	0.0	136.0	422.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	15.3	0.0	0.0	0.0	2,239.0	158.0	0.0	0.0	0.0	0.0	2,970.3
Retirements 2015	0.0	0.0	1,319.0	856.2	2.0	0.0	0.0	0.0	0.0	0.0	10.3	0.0	0.0	0.0	0.0	7,064.8	0.0	0.0	0.0	10.4	0.0	9,262.7
Retirements 2016	0.0	0.0	0.0	65.0	6.0	0.0	0.5	0.0	0.0	0.0	8.0	3.9	0.0	0.0	0.0	243.0	74.0	0.0	0.0	0.0	0.0	400.4
Retirements 2017	40.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.8	0.0	0.0	0.0	2,038.0	34.0	0.0	0.0	0.0	0.0	2,112.8
Retirements 2018	1.0	425.0	0.0	38.0	1.6	0.0	0.0	0.0	614.5	0.0	17.2	6.9	0.0	0.0	0.0	3,166.5	1,016.0	148.0	108.0	0.0	0.0	5,542.7
Retirements 2019	0.0	0.0	346.8	51.4	6.4	0.0	0.0	0.0	805.0	0.0	0.0	15.9	0.0	0.0	0.0	4,110.5	100.3	10.0	10.0	0.0	0.0	5,456.3
Retirements 2020	0.0	0.0	232.5	24.0	6.0	0.0	0.0	0.0	0.0	0.0	0.0	14.7	0.0	0.0	0.0	2,131.8	0.0	786.0	60.0	0.0	0.0	3,255.0
Retirements 2021	4.0	118.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	15.9	0.0	0.0	0.0	1,020.4	102.0	0.0	50.0	0.0	0.0	1,310.3
Retirements 2022	41.0	240.5	99.0	360.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	38.5	0.0	0.0	0.0	5,385.0	0.0	0.0	0.0	0.0	0.0	6,164.3
Retirements 2023	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Planned Retirements (April 1, 2023 and later)	0.0	0.0	281.8	15.9	0.0	0.0	0.0	0.0	0.0	0.0	34.0	19.2	0.0	0.0	0.0	4,184.0	1,326.0	953.0	50.0	0.0	0.0	6,863.9
Total	86.0	783.5	2,665.1	2,201.1	22.0	0.0	0.5	0.0	1,419.5	0.0	78.1	138.1	0.0	0.0	0.0	40,623.8	3,414.8	2,611.0	302.0	10.4	0.0	54,355.9

Table 12-7 shows the capacity, average size, and average age of units retiring in PJM, from 2011 through 2026, while Table 12-8 shows these retirements by state. Of the 55,355.9 MW of units that has been, or are planned to be, retired between 2011 and 2026, 40,623.8 MW (74.7 percent) are coal fired steam units. These coal fired steam units have an average age of 52.3 years and an average size of 218.4 MW. Over half of the retiring coal fired steam units, 53.9 percent, are located in Ohio or Pennsylvania.

Table 12-7 Retirements by unit type: 2011 through 2026

Unit Type	Number of Units	Avg. Size (MW)	Avg. Age at Retirement (Years)	Total MW	Percent
Battery	7	12.3	5.9	86.0	0.2%
Combined Cycle	6	130.6	29.1	783.5	1.4%
Combustion Turbine	140	25.4	35.9	4,888.2	9.0%
Natural Gas	68	39.2	41.8	2,665.1	4.9%
Oil	66	33.4	46.6	2,201.1	4.0%
Other	6	3.7	19.2	22.0	0.0%
Fuel Cell	0	0.0	0.0	0.0	0.0%
Hydro	1	0.5	113.8	0.5	0.0%
Pumped Storage	1	0.5	113.8	0.5	0.0%
Run of River	0	0.0	0.0	0.0	0.0%
Nuclear	2	709.8	47.2	1,419.5	2.6%
RICE	41	5.3	26.1	216.2	0.4%
Natural Gas	0	0.0	0.0	0.0	0.0%
Oil	15	5.2	40.4	78.1	0.1%
Other	26	5.3	11.8	138.1	0.3%
Solar	0	0	0	0	0.0%
Solar + Storage	0	0	0	0	0.0%
Solar + Wind	0	0	0	0	0.0%
Steam	226	181.7	45.7	46,951.6	86.4%
Coal	186	218.4	52.3	40,623.8	74.7%
Natural Gas	23	148.5	58.0	3,414.8	6.3%
Oil	8	326.4	47.0	2,611.0	4.8%
Other	9	33.6	25.3	302.0	0.6%
Wind	1	10.4	15.6	10.4	0.0%
Wind + Storage	0	0	0	0	0.0%
Total	424	128.2	44.9	54,355.9	100.0%

Table 12-8 Retirements (MW) by unit type and state: 2011 through 2026

State	Battery	Combined Cycle	CT - Natural Gas	CT - Oil	CT - Other	Fuel Cell	Hydro - Pumped Storage	Hydro - Run of River	Nuclear	RICE - Natural Gas	RICE - Oil	RICE - Other	Solar	Solar + Storage	Solar + Wind	Steam - Coal	Steam - Natural Gas	Steam - Oil	Steam - Other	Wind	Wind + Storage	Total
DC	0.0	0.0	0.0	240.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	548.0	0.0	0.0	0.0	788.0
DE	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	664.0	136.0	0.0	0.0	0.0	0.0	800.0
IL	41.0	0.0	296.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	35.7	0.0	0.0	0.0	2,818.1	1,326.0	0.0	0.0	0.0	0.0	4,516.8
IN	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	982.0	0.0	0.0	0.0	0.0	0.0	982.0
KY	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	995.0	0.0	0.0	0.0	0.0	0.0	995.0
MD	0.0	0.0	347.5	169.9	1.6	0.0	0.0	0.0	0.0	0.0	0.0	3.2	0.0	0.0	0.0	3,068.0	171.0	153.0	0.0	0.0	0.0	3,914.2
NC	0.0	0.0	0.0	31.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	324.5	0.0	0.0	0.0	0.0	0.0	355.5
NJ	0.0	465.5	1,820.2	1,066.2	6.4	0.0	0.5	0.0	614.5	0.0	8.0	24.4	0.0	0.0	0.0	2,001.9	932.5	148.0	10.0	0.0	0.0	7,098.1
OH	42.0	0.0	0.0	307.0	0.0	0.0	0.0	0.0	0.0	0.0	32.3	45.9	0.0	0.0	0.0	16,607.4	0.0	0.0	0.0	0.0	0.0	17,034.6
PA	1.0	51.0	121.4	307.3	14.0	0.0	0.0	0.0	805.0	0.0	13.9	20.5	0.0	0.0	0.0	5,296.0	286.3	176.0	109.0	10.4	0.0	7,211.8
TN	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	50.0	0.0	0.0	50.0
VA	0.0	267.0	80.0	79.7	0.0	0.0	0.0	0.0	0.0	0.0	23.9	8.4	0.0	0.0	0.0	3,897.9	563.0	1,586.0	133.0	0.0	0.0	6,638.9
WV	2.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	3,969.0	0.0	0.0	0.0	0.0	0.0	3,971.0
Total	86.0	783.5	2,665.1	2,201.1	22.0	0.0	0.5	0.0	1,419.5	0.0	78.1	138.1	0.0	0.0	0.0	40,623.8	3,414.8	2,611.0	302.0	10.4	0.0	54,355.9

Figure 12-4 is a map of unit retirements between 2011 and 2026, with a mapping to unit names in Table 12-9.

Figure 12-4 Map of unit retirements: 2011 through 2026

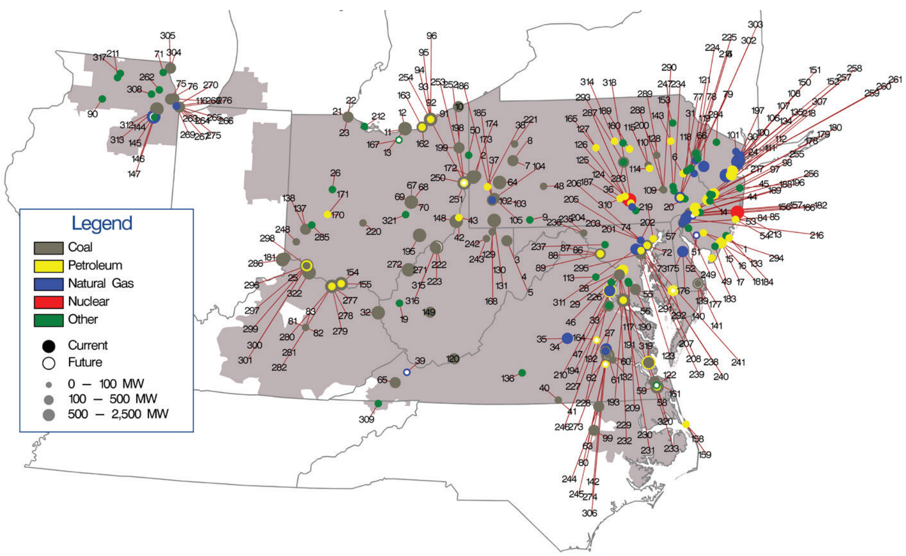


Table 12-9 Unit identification for map of unit retirements: 2011 through 2026

ID	Unit	ID	Unit	ID	Unit	ID	Unit	ID	Unit	ID	Unit
1	AC Landfill Units 1 and 2	61	Chesterfield 4	121	Glendon LF	181	Miami Fort 6	241	Riverside 8	301	Walter C Beckjord GT 1-4
2	AES Beaver Valley	62	Chesterfield 5	122	Gosport 1 F	182	Mickleton CT1	242	Riversville 5	302	Warren County Landfill
3	Albright 1	63	Chesterfield 6	123	Gould Street Generation Station	183	Middle 1-3	243	Riversville 6	303	Warren County NUG
4	Albright 2	64	Cheswick 1	124	Harrisburg 4 CT	184	Missouri Ave B,C,D	244	Roanoke Valley 1	304	Waukegan 7
5	Albright 3	65	Clinch River 3	125	Harrisburg CT 1	185	Mitchell 2	245	Roanoke Valley 2	305	Waukegan 8
6	Allentown CT 1-4	66	Columbia Dam Hydro	126	Harrisburg CT 2	186	Mitchell 3	246	Rockville CT	306	Weakley CT
7	Armstrong 1	67	Conesville 3	127	Harrisburg CT 3	187	Modern Power Landfill NUG	247	Rolling Hills Landfill Generator	307	Werner 1-4
8	Armstrong 2	68	Conesville 4	128	Harwood 1-2	188	Monmouth NUG landfill	248	SMART Paper	308	West Chicago Energy Storage
9	Arnold (Green Mtn. Wind Farm	69	Conesville 5	129	Hatfield's Ferry 1	189	Montour ATG	249	Salem County LF	309	West Kingsport LF
10	Ashtabula 5	70	Conesville 6	130	Hatfield's Ferry 2	190	Morgantown CT1	250	Sammis 1-4	310	West Shore CT 1-2
11	Avon Lake 10	71	Countryside Landfill	131	Hatfield's Ferry 3	191	Morgantown CT2	251	Sammis Diesel Units	311	Westport 5
12	Avon Lake 7	72	Crane 1	132	Hopewell James River Cogeneration	192	Morgantown Unit 1	252	Sammis Unit 5	312	Will County 3
13	Avon Lake 9	73	Crane 2	133	Howard Down 10	193	Morgantown Unit 2	253	Sammis Unit 6	313	Will County 4
14	BC Landfill	74	Crane GT1	134	Hudson 1	194	Morris Landfill Generator	254	Sammis Unit 7	314	Williamsport-Lycoming CT 1-2
15	BL England 1	75	Crawford 7	135	Hudson 2	195	Muskingum River 1-5	255	Schuylkill 1	315	Willow Island 1
16	BL England 2	76	Crawford 8	136	Hurt NUG	196	National Park 1	256	Schuylkill Diesel	316	Willow Island 2
17	BL England 3	77	Cromby 1	137	Hutchings 1-3, 5-6	197	New Bay Cogen CC	257	Sewaren 1	317	Winnebago Landfill
18	BL England Diesel Units 1-4	78	Cromby 2	138	Hutchings 4	198	Niles 1	258	Sewaren 2	318	York Generation Facility
19	Balls Gap Battery Facility	79	Cromby D	139	Indian River 1	199	Niles 2	259	Sewaren 3	319	Yorktown 1-2
20	Barbados AES Battery	80	DINWIDDIE 1 CT	140	Indian River 3	200	Northeastern Power NEPCO	260	Sewaren 4	320	Yorktown 3
21	Bay Shore 2	81	Dale 1-2	141	Indian River 4	201	Notch Cliff GT1	261	Sewaren 6	321	Zanesville Landfill
22	Bay Shore 3	82	Dale 3	142	Ingenco Petersburg	202	Notch Cliff GT2	262	Solberg 1 BT	322	Zimmer 1
23	Bay Shore 4	83	Dale 4	143	Jenkins CT 1-2	203	Notch Cliff GT3	263	Southeast Chicago CT11		
24	Bayonne Cogen Plant (CC)	84	Deepwater 1	144	Joliet 6	204	Notch Cliff GT4	264	Southeast Chicago CT12		
25	Beckjord Battery Unit 2	85	Deepwater 6	145	Joliet 7	205	Notch Cliff GT5	265	Southeast Chicago CT5		
26	Bellefontaine Landfill Generating Station	86	Dickerson CT1	146	Joliet 8	206	Notch Cliff GT6	266	Southeast Chicago CT6		
27	Bellemeade	87	Dickerson Unit 1	147	Joliet Energy Storage	207	Notch Cliff GT7	267	Southeast Chicago CT7		
28	Benning 15	88	Dickerson Unit 2	148	Kammer 1-3	208	Notch Cliff GT8	268	Southeast Chicago CT8		
29	Benning 16	89	Dickerson Unit 3	149	Kanawha River 1-2	209	Oaks Landfill	269	Southeast Chicago GT10		
30	Bergen 3	90	Dixon Lee Landfill Generator	150	Kearny 10	210	Occoquan 1 LF	270	Southeast Chicago GT9		
31	Bethlehem Renewable Energy Generator (Landfill)	91	Eastlake 1	151	Kearny 11	211	Orchard Hills LF	271	Sporn 1-4		
32	Big Sandy 2	92	Eastlake 2	152	Kearny 9	212	Ottawa County Project	272	Sporn 5		
33	Birchwood Plant	93	Eastlake 3	153	Keystone Recovery (Units 1 - 7)	213	Oyster Creek	273	Spruance NUG1 (Rich 1-2)		
34	Bremo 3	94	Eastlake 4	154	Killen 2	214	PL MARTINS CREEK 1-4 CT	274	Spruance NUG2 (Rich 3-4)		
35	Bremo 4	95	Eastlake 5	155	Killen CT	215	PL MARTINS CREEK 1-4 CT	275	State Line 3		
36	Brunner Island Diesels	96	Eastlake 6	156	Kimberly Clark Generator	216	Pedricktown Cogen CC	276	State Line 4		
37	Brunot Island 1B	97	Eddystone 1	157	Kinsley Landfill	217	Pennsbury Generator Landfill 1	277	Stuart 1		
38	Brunot Island 1C	98	Eddystone 2	158	Kitty Hawk GT 1	218	Pennsbury Generator Landfill 2	278	Stuart 2		
39	Buchanan 1-2	99	Edgecomb NUG (Rocky 1-2)	159	Kitty Hawk GT 2	219	Perryman 2	279	Stuart 3		
40	Buggs Island 1 (Mecklenberg)	100	Edison 1-3	160	Koppers Co. IPP	220	Picway 5	280	Stuart 4		
41	Buggs Island 2 (Mecklenberg)	101	Elmwood Park Power	161	Lake Kingman	221	Piney Creek NUG	281	Stuart Diesels 1-4		
42	Burger 3	102	Elrama 1	162	Lake Shore 18	222	Pleasant Unit 1	282	Stuart Diesels 1-4		
43	Burger EMD	103	Elrama 2	163	Lake Shore EMD	223	Pleasant Unit2	283	Sunbury 1-4		
44	Burlington 8,11	104	Elrama 3	164	Lanier 1 CT	224	Portland 1	284	Sussex County LF		
45	Burlington 9	105	Elrama 4	165	Lock Haven CT 1	225	Portland 2	285	Tait Battery		
46	Buzzard Point East Banks 1,2,4-8	106	Essex 10-11	166	Logan	226	Possum Point 3	286	Tanners Creek 1-4		
47	Buzzard Point West Banks 1-9	107	Essex 12	167	Lorain 1 LF	227	Possum Point 4	287	Three Mile Island Unit 1		
48	Cambria CoGen	108	Essex 9	168	MEA NUG (WVU)	228	Possum Point 5	288	Titus 1		
49	Cape May County Municipal LF	109	Evergreen Power United Corstack	169	MH50 Markus Hook Co-gen	229	Potomac River 1	289	Titus 2		
50	Carbon Limestone LF	110	FRACKVILLE WHEELABRATOR 1	170	Mad River CTs A	230	Potomac River 2	290	Titus 3		
51	Carlls Corner CT1	111	Fairless Hills Landfill A	171	Mad River CTs B	231	Potomac River 3	291	Vienna 8		
52	Carlls Corner CT2	112	Fairless Hills Landfill B	172	Mansfield 1	232	Potomac River 4	292	Vienna CT 10		
53	Cedar 1	113	Fauquier County Landfill	173	Mansfield 2	233	Potomac River 5	293	Viking Energy NUG		
54	Cedar 2	114	Fishbach CT 1	174	Mansfield 3	234	Pottstown LF (Moser)	294	Vineland West CT		
55	Chalk Point Unit 1	115	Fishbach CT 2	175	McKee 1	235	R Paul Smith 3	295	Wagner 2		
56	Chalk Point Unit 2	116	Fisk Street 19	176	McKee 2	236	R Paul Smith 4	296	Walter C Beckjord 1		
57	Chambers CCLP	117	GUDE Landfill	177	McKee 3	237	Reichs Ford Road Landfill Generator	297	Walter C Beckjord 2		
58	Chesapeake 1-4	118	Gilbert 1-4	178	Mercer 1	238	Riverside 4	298	Walter C Beckjord 3		
59	Chesapeake 7-10	119	Glen Gardner 1-8	179	Mercer 2	239	Riverside 6	299	Walter C Beckjord 4		
60	Chesterfield 3	120	Glen Lyn 5-6	180	Mercer 3	240	Riverside 7	300	Walter C Beckjord 5-6		

Current Year Generation Retirements

Table 12-10 shows that in the first three months of 2023, there were no generation retirements.

Table 12-10 Unit deactivations: January through March, 2023

Company	Unit Name	ICAP (MW)	Unit Type	Zone Name	Age (Years)	Retirement Date
None						
Total		0.0				

Planned Generation Retirements

Table 12-11 shows that, as of March 31, 2023, there are 6,863.9 MW of generation that have requested retirement after March 31, 2023. Of the 6,863.9 MW requesting retirement, 4,184.0 MW (61.0 percent) are coal fired steam units. As of March 31, 2023, there are planned coal fired unit retirements in four different PJM zones. Of the 6,863.9 MW of planned retirements, 1,522.2 MW (22.2 percent) are located in the ATSI Zone. Of the generation requesting retirement in the ATSI Zone, 1,490.0 MW (97.9 percent) are coal fired steam units.

Table 12-11 Planned retirement of units: March 31, 2023

Company	Unit Name	ICAP (MW)	Unit Type	Zone Name	Projected Deactivation Date
American Municipal Power, Inc.	Lorain 1 LF	19.2	RICE-Other	ATSI	01-Apr-23
Dominion Energy, Inc.	Chesterfield 5	336.0	Steam-Coal	DOM	31-May-23
Dominion Energy, Inc.	Chesterfield 6	670.0	Steam-Coal	DOM	31-May-23
Dominion Energy, Inc.	Yorktown 3	800.0	Steam-Oil	DOM	31-May-23
LS Power Equity Partners, L.P.	Buchanan 1-2	80.0	CT-Natural Gas	AEP	01-Jun-23
BP P.L.C.	DINWIDDIE 1 CT	3.0	RICE-Oil	DOM	01-Jun-23
NRG Energy Inc	Joliet 6	290.0	Steam-Natural Gas	COMED	01-Jun-23
NRG Energy Inc	Joliet 7	518.0	Steam-Natural Gas	COMED	01-Jun-23
NRG Energy Inc	Joliet 8	518.0	Steam-Natural Gas	COMED	01-Jun-23
BP P.L.C.	Lanier 1 CT	7.0	RICE-Oil	DOM	01-Jun-23
Riverstone Holdings LLC	Martins Creek CT 1	18.0	CT-Natural Gas	PPL	01-Jun-23
Riverstone Holdings LLC	Martins Creek CT 2	17.3	CT-Natural Gas	PPL	01-Jun-23
Riverstone Holdings LLC	Martins Creek CT 4	17.3	CT-Natural Gas	PPL	01-Jun-23
Avenue Capital Group LLC	Pleasant Unit 1	639.0	Steam-Coal	APS	01-Jun-23
Avenue Capital Group LLC	Pleasant Unit2	639.0	Steam-Coal	APS	01-Jun-23
BP P.L.C.	Rockville CT	4.0	RICE-Oil	DOM	01-Jun-23
Avenue Capital Group LLC	Sammis Diesel Units	13.0	RICE-Oil	ATSI	01-Jun-23
Avenue Capital Group LLC	Sammis Unit 5	290.0	Steam-Coal	ATSI	01-Jun-23
Avenue Capital Group LLC	Sammis Unit 6	600.0	Steam-Coal	ATSI	01-Jun-23
Avenue Capital Group LLC	Sammis Unit 7	600.0	Steam-Coal	ATSI	01-Jun-23
BP P.L.C.	Weakley CT	7.0	RICE-Oil	DOM	01-Jun-23
Energy Capital Partners LLC	Carlls Corner CT1	37.4	CT-Natural Gas	ACEC	01-Jun-24
Energy Capital Partners LLC	Carlls Corner CT2	41.2	CT-Natural Gas	ACEC	01-Jun-24
Energy Capital Partners LLC	Mickleton CT1	70.6	CT-Natural Gas	ACEC	01-Jun-24
Macquarie Group Limited	Gosport 1 F	50.0	Steam-Other	DOM	01-Jul-24
NRG Energy Inc	Vienna 8	153.0	Steam-Oil	DPL	01-Jun-25
NRG Energy Inc	Vienna CT 10	15.9	CT-Oil	DPL	01-Jun-25
NRG Energy Inc	Indian River 4	410.0	Steam-Coal	DPL	31-Dec-26

In addition to the 6,863.9 MW of announced unit retirements as of March 31, 2023, there are significantly more unit retirements expected as a result of state environmental actions. PJM anticipates an additional 20,000 MW of unit retirements between 2024 and 2030, and an additional 10,000 MW of unit retirements between 2031 and 2045.[30]

30 See "Illinois Generation Retirement Study," (August 3, 2022). <http://www.pjm.com/-/media/library/reports-notices/special-reports/2022/2022-pjm-illinois-generation-retirement-study.ashx>.

Generation Queue[31]

Any entity that requests interconnection of a new generating facility, including increases to the capacity of an existing generating unit, or that requests interconnection of a merchant transmission facility, must follow the process defined in the PJM tariff to obtain interconnection service.[32] PJM's process is designed to ensure that new generation is added in a reliable and systematic manner. The process is complex and time consuming at least in part as a result of the required analyses. The cost, time and uncertainty associated with interconnecting to the grid may create barriers to entry for potential entrants. But the behavior of project developers also creates issues with queue management and exacerbates the barriers.

Generation request queues are groups of proposed projects, including new units, reratings of existing units, capacity resources and energy only resources. Each queue is open for a fixed amount of time. Studies commence on all projects in a given queue when that queue closes. Queues A and B were open for one year. Queues C through T were open for six months. Starting in February 2008, Queues U through Y1 were open for three months. In May 2012, the duration of the queue period was reset to six months, starting with Queue Y2. Queue AI2 opened on October 1, 2022 and closed on March 10, 2023. On June 24, 2021, PJM requested tariff modifications to close queue windows on September 10 and March 10, rather than September 30 and March 31.[33] This change allows more time to review the new requests to the queue without shortening the amount of time available for the resulting model builds and analyses. On August 23, 2021, the Commission approved the tariff modifications.[34]

Projects submitted to the queue undergo a deficiency review to ensure that all required information is provided. If a project is missing information, or if the submitting developer owes money from a prior queue request, the submission is defined to be deficient. PJM was required to perform the review and provide notification within five business days of receipt of the request. The developer had ten business days to respond. PJM had five business days to review the response. As a result of the large number of project submissions submitted close to the end of each queue window, PJM could not meet the required timeline. On June 24, 2021, PJM filed tariff changes to modify the deficiency review timeline.[35] PJM requested an increase in the initial notification to the interconnection customer from five to 15 business days, or as soon thereafter as practicable, making the deadline flexible. The developer has ten business days to respond. PJM requested an increase in PJM's time to respond from five to 15 business days, or as soon thereafter as practicable, making the deadline flexible. On August 23, 2021, the Commission approved the tariff modifications.[36] A queue position is assigned once the project has met the submission requirements. Projects that do not meet submission requirements are removed from the queue.

All projects that have entered a queue and have met the submission requirements have a status assigned. Projects listed as active are undergoing one of the studies (feasibility, system impact, facility) required to proceed. Other status options are under construction, suspended, and in service. A project cannot be suspended until it has reached the status of under construction. Any project that entered the queue before February 1, 2011, can be suspended for up to three years. Projects that entered the queue after February 1, 2011, face an additional restriction in that the suspension period is reduced to one year if they affect any project later in the queue.[37] When a project is suspended, PJM extends the scheduled milestones by the duration of the suspension. If, at any time, a milestone is not met, PJM will initiate the termination of the Interconnection Service Agreement (ISA) and the corresponding cancellation costs must be paid by the customer.[38]

PJM has generally met the deadlines for feasibility and system impact studies. The increase in the number of projects submitted have contributed to a significant backlog in performing timely facility studies. The facility study includes the conceptual design, stability analyses and determines the network upgrades, and the costs associated with those upgrades. Modifications to proposed facilities and restudies resulting from the withdrawal of projects

31 The queue totals in this report are the winter net MW energy for the interconnection requests ("MW Energy") as shown in the queue.
32 See OATT Parts IV & VI.
33 See PJM Filing, Docket ER21-2203 (June 24, 2021).
34 176 FERC ¶ 61,117 (2021).
35 See PJM Filing, Docket ER21-2203 (June 24, 2021).
36 176 FERC ¶ 61,117 (2021).
37 See "PJM Manual 14C: Generation and Transmission Interconnection Process," Rev. 14 (January 27, 2021).
38 PJM does not track the duration of suspensions or PJM termination of projects.

from the queue also affect the time to complete a facility study. The PJM queue evaluation process should continue to be improved to help ensure that barriers to competition from new generation investments are not created. The PJM queue evaluation process should also evaluate and address the incentives to project developers to act in ways that are not consistent with an effective and efficient queue process for the system. For example, when developers put multiple projects in the queue to maintain their own optionality while planning to build only one they also affect all the projects that follow them in the queue by requiring multiple restudies.

In 2022, after a lengthy stakeholder process (Interconnection Process Reform Task Force (IPRTF)) PJM filed significant changes to improve overall queue management. On November 29, 2022, the Commission issued an order accepting PJM's tariff revisions modifying how PJM manages the new services queue.[39] The new queue process includes modifications to implement a cluster/cycle based processing method to replace the first in/first out processing method.[40] This change will allow projects to move forward based on a first ready/first out analysis, where readiness is demonstrated through site control and financial milestones and there is an option to exit the study process early based on system impacts.

The new process includes a transition process which treats projects based on their current queue status. All projects through queue window AD2 will continue as part of the previous queue process. The transition process assigns existing queue projects in queue windows AE1 through AH1 to transition cycle 1 and transition cycle 2 and also provides for the expedited treatment (fast track) of projects submitted in the AE1 through AG1 queue windows with upgrade costs less than $5 million. Transition cycle 1 is expected to begin in late 2023. Transition cycle 2 is expected to begin in late 2024. Projects submitted in queue window AH2 and beyond will be evaluated starting in early 2026. While new applications will continue to be accepted, the transition process will delay their consideration for an unknown period.

39 181 FERC ¶ 61,162 (2022).

40 See "Interconnection Process Reform," presented at April 27, 2022 meeting of the Members Committee. <https://www.pjm.com/-/media/committees-groups/committees/mc/2022/20220427/20220427-item-01a-1-interconnection-process-reform-presentation.ashx>.

The new process includes modifications to implement a cluster/cycle based processing method to replace the first in/first out processing method.[41] This change will allow projects to move forward based on a first ready/first out analysis, where readiness is demonstrated through site control and financial milestones and there is an option to exit the study process early based on system impacts. The new process also includes defining progress to completion through three phases, with a customer decision at the end of each. The new process requires a stronger definition of site control, and includes readiness deposits (some of which are nonrefundable) based on the phase of development. Additional process modifications include limits to technology changes, improvements to the application review phase, removal of optional interconnection study processes, modifications to the study schedules to reduce the number of restudies required in the event of project modifications, adjusting the queue window schedule to coincide with the previous clusters' milestones, and modifications to cost responsibility by assigning responsibility to all projects within a queue cycle. The new process should help to reduce backlog and to remove projects that are not viable earlier to help improve the overall efficiency of the queue process.

The new process includes a transition process which treats projects based on their current queue status. All projects through queue window AD2 will continue as part of the existing queue process. The transition process assigns existing queue projects in queue windows AE1 through AH1 to transition cycle 1 and transition cycle 2 and also provides for the expedited treatment (fast track) of projects submitted in the AE1 through AG1 queue windows with upgrade costs less than $5 million. Transition cycle 1 is expected to begin in late 2023. Transition cycle 2 is expected to begin in late 2024. Projects submitted in queue window AH2 and beyond will be evaluated starting in early 2026. While new applications will continue to be accepted, the transition process will delay their consideration for an unknown period. The transition process itself will not begin until projects eligible for the existing queue process have an executed ISA or the equivalent. After the process for projects in transition cycles 1 and 2 has been completed, projects in queue AH2 and possible subsequent queues will be studied. The new process will not be fully

41 See "Interconnection Process Reform," presented at April 27, 2022 meeting of the Members Committee. <https://www.pjm.com/-/media/committees-groups/committees/mc/2022/20220427/20220427-item-01a-1-interconnection-process-reform-presentation.ashx>.

implemented until PJM provides notice that it is accepting applications for the first cycle entirely under the new process. That notice will be provided only after PJM has complete all the prior required transition steps.

On July 15, 2021, the Commission issued an Advance Notice of Proposed Rulemaking (ANOPR).[42] The purpose of the ANOPR is to review transmission related regulations and determine whether additional reforms to the regional transmission planning, cost allocation and generator interconnection processes are needed. The ANOPR discusses the impacts of transmission rules on the competitiveness of the energy markets but does not focus on the competitiveness of transmission itself. Given that the cost of transmission is increasing as a share of total wholesale power costs and now exceeds the cost of capacity in PJM, the cost effectiveness and competitiveness of the transmission planning and procurement process should be addressed when considering reforms.

On June 16, 2022, the Commission issued a Notice of Proposed Rulemaking (NOPR).[43] The NOPR largely aligned with the PJM proposal that has been accepted by FERC.[44] The NOPR addresses reforms to implement a first ready/first served cluster study process, including cluster study costs and an allocation of network upgrade costs to the cluster, increased financial commitments and readiness requirements and improvements to the speed of the queue processing.

The MMU recommends improvements in queue management including that PJM establish a review process to ensure that projects are removed from the queue if they are not viable, as well as a process to allow commercially viable projects to advance in the queue ahead of projects which have failed to make progress, subject to rules to prevent gaming.[45]

Interconnection Process Studies and Agreements[46]

In the study stage of the interconnection planning process, a series of studies are performed to determine the feasibility, impact, and cost of projects in the queue. Table 12-12 is an overview of the studies PJM perform in the study stage of the interconnection process. System impact and facilities studies are often redone when a project is withdrawn in order to determine the impact on the projects remaining in the queue.

Table 12-12 Interconnection planning process: study stage

Study	Purpose
Feasibility Study	The feasibility study determines preliminary estimates of the type, scope, cost and lead time for construction of facilities required to interconnect the project.
System Impact Study	The system impact study is a comprehensive regional analysis of the impact of adding the new generation and/or transmission facility to the system. The study identifies the system constraints related to the project and the necessary attachment facilities, local upgrades, and network upgrades. The study refines and more comprehensively estimates cost responsibility and construction lead times for facilities and upgrades.
Facilities Study	In the facilities study, stability analysis is performed and the system impact study results are modified as necessary to reflect changes in the characteristics of other projects in the queue.

In 2016, the PJM Earlier Queue Submitted Task Force stakeholder group made changes to the interconnection process to address some of the issues related to delays observed in the various stages of the study phase. The changes became effective with the AC2 Queue that closed on March 31, 2017. The MMU recommends continuing analysis of the study phase of PJM's transmission planning to reduce the need for postponements of study results, to decrease study completion times, and to improve the likelihood that a project at a given phase in the study process will successfully go into service.

42 See *Building for the Future through Electric Regional Transmission Planning and Cost Allocation and Generator Interconnection*, Advanced Notice of Proposed Rulemaking, 176 FERC ¶ 61,024 (July 15, 2021).
43 See *Improvements to Generator Interconnection Procedures and Agreements*, Notice of Proposed Rulemaking, 179 FERC ¶ 61,194 (June 16, 2022).
44 181 FERC ¶ 61,162 (2022).
45 Once implemented, the approved solutions from PJM's Interconnection Process Reform Task Force (IPRTF) should result in improvements in these areas.
46 See "PJM Manual 14A: New Services Request Process," Rev. 29 (August 24, 2021) for a complete explanation of the interconnection process studies and agreements.

In addition to the feasibility, system impact and facilities studies, PJM may also perform additional studies under certain circumstances. These studies include the affected systems study, interim deliverability study and the long term firm transmission studies. Table 12-13 is an overview of the additional studies PJM may perform.

Table 12-13 Interconnection planning process: study stage – additional studies

Study	Purpose
Affected System Study	PJM and its neighboring balancing authorities conduct interconnection studies to determine the impacts of interconnection requests on the neighboring transmission system.
Interim Deliverability Studies	Interim deliverability studies are conducted on a periodic basis in support of RPM auctions and other interconnection studies to determine if a new facility may come on line prior to its scheduled date. These studies evaluate the available system capability and provide the customer(s) with the availability of service by planning year. Interim deliverability studies use the same criteria used for the evaluation of the need for reinforcements associated with a project under study.
Long Term Firm Transmission Studies	Transmission service requests that extend beyond the available transfer capability horizon of 18 months are evaluated along with the other requests for service in the PJM new services queue to ensure deliverability. Long term firm transmission studies follow the same feasibility, system impact and facilities study process as new generation.

After the completion of a facility study, the project will enter the construction stage of the interconnection process. The final agreements required depend on the type of project. These agreements include a Construction Service Agreement (CSA), Interconnection Service Agreement (ISA), Upgrade Construction Service Agreement (UCSA), Wholesale Market Participant Agreement (WMPA) or Transmission Service Agreement (TSA). Table 12-14 is an overview of the agreements in the construction stage of the interconnection process.

Table 12-14 Interconnection planning process: construction stage agreements

Agreement	Purpose
Interconnection Service Agreement (ISA)	An ISA defines the generation or transmission developer's cost responsibility for required system upgrades. For generation interconnection customers, the ISA defines the capacity interconnection rights for a capacity resource and any operational restrictions or other limitations. For transmission interconnection customers, the ISA defines transmission injection and withdrawal rights and applicable incremental delivery, available transfer capability revenue and auction revenue rights.
Interim Interconnection Service Agreements (I-ISA)	If a developer wishes to start project construction activities prior to completion of the generation or transmission interconnection facilities study, the interim ISA would commit the developer to pay all costs incurred for the construction activities being advanced.
Interconnection Construction Service Agreement (CSA)	The CSA defines the standard terms and conditions of the interconnection, including construction responsibility, includes a construction schedule and contains notification and insurance obligations.
Upgrade Construction Service Agreement (USCA)	A new service customer who proposes to make an upgrade to an existing transmission facility or who seeks incremental auction revenue rights (IARRs) will receive an upgrade construction service agreement after their study process is completed.
Wholesale Market Participation Agreement (WMPA)	Developers interconnecting to non-FERC jurisdictional facilities who intend to participate in the PJM wholesale market will receive a three party agreement (WMPA). The WMPA is a non-Tariff agreement which must be filed with the FERC. The WMPA is essentially an ISA without interconnection provisions.

Planned Generation Additions

Expected net revenues provide incentives to build new generation to serve PJM markets. The amount of planned new generation in PJM reflects investors' perception of the incentives provided by the combination of revenues from the PJM energy, capacity and ancillary service markets and from federal and state subsidies and incentives. On March 31, 2023, 288,157.8 MW were in generation request queues for construction through 2029. Although it is clear that not all generation in the queues will be built, PJM has added capacity steadily since markets were implemented on April 1, 1999.[47]

47 See "*PJM Generation Capacity and Funding Sources 2007/2008 through 2021/2022 Delivery Years,*" <http://www.monitoringanalytics.com/reports/Reports/2020/IMM_2020_PJM_Generation_Capacity_and_Funding_Sources_20072008_through_20212022_DY_20200915.pdf>.

There were 287,492.7 MW in generation queues, in the status of active, under construction or suspended, at the end of 2022. In the first three months of 2023, the AI2 window remained open, closing on March 10, 2023.[48] As projects move through the queue process, projects can be removed from the queue due to incomplete or invalid data, withdrawn by the market participant or placed in service. On March 31, 2023, there were 288,157.8 MW in generation queues, in the status of active, under construction or suspended, an increase of 665.1 MW (0.2 percent) from December 31, 2022. Table 12-15 shows MW in queues by expected completion year and MW changes in the queue between December 31, 2022, and March 31, 2023, for ongoing projects, i.e. projects with the status active, under construction or suspended.[49]

Table 12-15 Queue comparison by expected completion year (MW): December 31, 2022 and March 31, 2023[50]

			Year Change	
Year	As of 12/31/2022	As of 3/31/2023	MW	Percent
2008	0.0	0.0	0.0	0.0%
2009	0.0	0.0	0.0	0.0%
2010	0.0	0.0	0.0	0.0%
2011	0.0	0.0	0.0	0.0%
2012	0.0	0.0	0.0	0.0%
2013	0.0	0.0	0.0	0.0%
2014	0.0	0.0	0.0	0.0%
2015	0.0	0.0	0.0	0.0%
2016	3.4	3.4	0.0	0.0%
2017	0.0	0.0	0.0	0.0%
2018	84.6	44.6	(40.0)	(47.3%)
2019	987.6	987.6	0.0	0.0%
2020	4,291.8	3,048.8	(1,243.0)	(29.0%)
2021	18,227.3	16,331.6	(1,895.7)	(10.4%)
2022	35,065.8	33,139.9	(1,925.9)	(5.5%)
2023	55,134.4	55,610.2	475.8	0.9%
2024	65,091.8	66,301.7	1,210.0	1.9%
2025	48,274.4	50,418.9	2,144.5	4.4%
2026	25,603.5	27,748.5	2,145.0	8.4%
2027	14,972.0	15,923.7	951.7	6.4%
2028	6,103.8	7,350.8	1,247.0	20.4%
2029	9,358.1	9,358.1	0.0	0.0%
2030	290.0	290.0	0.0	0.0%
2031	1,600.0	1,600.0	0.0	0.0%
Total	285,088.4	288,157.8	3,069.4	1.1%

Table 12-16 shows the project status changes in more detail and how scheduled queue MW have changed between December 31, 2022, and March 31, 2023. For example, 3,069.4 MW entered the queue in the first three months of 2023. Of the total 273,456.3 MW marked as active on December 31, 2022, 1,715.1 MW were withdrawn, 1,833.0 MW were suspended, 408.6 MW started construction, and 105.3 MW went into service by March 31, 2023. Analysis of projects that were suspended on December 31, 2022 show that 663.3 MW came out of suspension and are now active as of March 31, 2023.

48 The AI2 queue window opened on October 1, 2022.
49 Expected completion dates are entered when the project enters the queue. Actual completion dates are generally different than expected completion dates.
50 Wind and solar capacity in Table 12-11 through Table 12-15 have not been adjusted to reflect derating.

Table 12-16 Change in project status (MW): December 31, 2022 to March 31, 2023

		Status at 3/31/2023				
Status at 12/31/2022	Total at 12/31/2022	Active	In Service	Under Construction	Suspended	Withdrawn
(Entered during 2023)	0.0	3,069.4	0.0	0.0	0.0	0.0
Active	273,456.3	269,394.3	105.3	408.6	1,833.0	1,715.1
In Service	81,295.0	0.0	81,294.0	0.0	0.0	1.0
Under Construction	7,433.6	0.0	230.8	7,171.4	0.0	31.4
Suspended	6,281.0	663.3	0.0	0.0	5,617.7	0.0
Withdrawn	449,592.9	0.0	0.0	0.0	0.0	449,592.9
Total	818,058.8	273,127.0	81,630.1	7,580.0	7,450.7	451,340.4

On March 31, 2023, 288,157.8 MW were in generation request queues in the status of active, suspended or under construction. Table 12-17 shows each status by unit type. Of the 273,127.0 MW in the status of Active on March 31, 2023, 5,538.7 MW (2.0 percent) were combined cycle projects. Of the 7,580.0 MW in the status of under construction, 3,272.7 MW (43.2 percent) were combined cycle projects. A significant amount of renewable hybrid projects (defined as solar + storage, solar + wind and wind + storage projects) have entered the queue in recent years. Of the 273,127.0 MW in the status of Active on March 31, 2023, 39,555.3 MW (14.5 percent) were renewable hybrid projects. Of the 7,580.0 MW in the status of under construction, 22.7 MW (0.3 percent) were renewable hybrid projects.

Table 12-17 Current project status (MW) by unit type: March 31, 2023

	Battery	Combined Cycle	CT - Natural Gas	CT - Oil	CT - Other	Fuel Cell	Hydro - Pumped Storage	Hydro - Run of River	Nuclear	RICE - Natural Gas	RICE - Oil	RICE - Other	Solar	Solar + Storage	Solar + Wind	Steam - Coal	Steam - Natural Gas	Steam - Oil	Steam - Other	Wind	Wind + Storage	Total
Active	54,360.0	5,538.7	3,819.2	0.0	53.8	5.0	730.0	112.8	0.0	14.4	0.0	0.0	123,077.8	39,196.3	209.0	29.0	0.0	0.0	20.0	45,811.1	150.0	273,127.0
Suspended	27.0	3,950.0	675.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2,449.3	259.4	0.0	0.0	0.0	0.0	0.0	0.0	90.0	7,450.7
Under Construction	35.0	3,272.7	457.0	9.0	0.0	3.0	0.0	0.0	44.0	0.0	0.0	0.0	3,408.0	22.7	0.0	36.0	5.0	0.0	0.0	287.6	0.0	7,580.0
Total	54,422.0	12,761.4	4,951.2	9.0	53.8	8.0	730.0	112.8	44.0	14.4	0.0	0.0	128,935.2	39,478.4	209.0	65.0	5.0	0.0	20.0	46,098.7	240.0	288,157.8

A significant shift in the distribution of unit types within the PJM footprint continues to develop as natural gas fired units and renewable, hybrid and other intermittent resources enter the queue and coal fired steam units retire. As of March 31, 2023, of the 288,157.8 MW in the generation request queues in the status of active, suspended or under construction, 128,935.2 MW (44.7 percent) were solar projects, 46,098.7 MW (16.0 percent) were wind projects, 17,732.0 MW (6.2 percent) were natural gas fired projects (including combined cycle units, CTs, RICE units, and natural gas fired steam units), 39,937.4 MW (13.9 percent) were renewable hybrid projects (solar + storage, solar + wind and wind + storage units), and 65.0 MW (0.02 percent) were coal fired steam projects.

As of March 31, 2023, there are 4,184.0 MW of coal fired steam units and 1,607.8 MW of natural gas units slated for deactivation between April 1, 2023, and December 31, 2026 (See Table 12-11). The ongoing replacement of coal fired steam units by natural gas units will continue to significantly affect future congestion, the role of firm and interruptible gas supply, and natural gas supply infrastructure. The growing level of renewables, hybrids and other intermittents will also have increasingly significant impacts on the energy and capacity markets.

Table 12-18 shows the total MW in the status of active, in service, under construction, suspended, or withdrawn for each queue since the beginning of the RTEP process and the total MW that had been included in each queue. All items in queues A-R are either in service or have been withdrawn. As of March 31, 2023, there are 288,157.8 MW in queues that are not yet in service or withdrawn, of which 2.6 percent are suspended, 2.6 percent are under construction and 94.8 percent have not begun construction.

Table 12-18 Queue totals by status (MW): March 31, 2023[51]

Queue	Active	In Service	Under Construction	Suspended	Withdrawn	Total
A Expired 31-Jan-98	0.0	9,094.0	0.0	0.0	17,252.0	26,346.0
B Expired 31-Jan-99	0.0	4,292.4	0.0	0.0	14,958.8	19,251.2
C Expired 31-Jul-99	0.0	531.0	0.0	0.0	3,558.3	4,089.3
D Expired 31-Jan-00	0.0	850.6	0.0	0.0	7,358.0	8,208.6
E Expired 31-Jul-00	0.0	795.2	0.0	0.0	8,021.8	8,817.0
F Expired 31-Jan-01	0.0	52.0	0.0	0.0	3,092.5	3,144.5
G Expired 31-Jul-01	0.0	1,171.6	0.0	0.0	17,961.8	19,133.4
H Expired 31-Jan-02	0.0	702.5	0.0	0.0	8,421.9	9,124.4
I Expired 31-Jul-02	0.0	103.0	0.0	0.0	3,728.4	3,831.4
J Expired 31-Jan-03	0.0	42.0	0.0	0.0	846.0	888.0
K Expired 31-Jul-03	0.0	93.1	0.0	0.0	485.3	578.4
L Expired 31-Jan-04	0.0	256.5	0.0	0.0	4,033.7	4,290.2
M Expired 31-Jul-04	0.0	504.8	0.0	0.0	3,705.6	4,210.4
N Expired 31-Jan-05	0.0	2,398.8	0.0	0.0	8,129.3	10,528.0
O Expired 31-Jul-05	0.0	1,890.2	0.0	0.0	5,466.8	7,357.0
P Expired 31-Jan-06	0.0	3,290.3	0.0	0.0	5,320.5	8,610.8
Q Expired 31-Jul-06	0.0	3,147.9	0.0	0.0	11,385.7	14,533.6
R Expired 31-Jan-07	0.0	1,892.5	0.0	0.0	20,708.9	22,601.4
S Expired 31-Jul-07	70.0	3,543.5	0.0	0.0	12,396.5	16,010.0
T Expired 31-Jan-08	0.0	4,196.5	0.0	0.0	23,313.3	27,509.8
U1 Expired 30-Apr-08	0.0	218.9	0.0	0.0	7,937.8	8,156.7
U2 Expired 31-Jul-08	0.0	716.9	0.0	0.0	16,218.6	16,935.5
U3 Expired 31-Oct-08	0.0	333.0	0.0	0.0	2,635.6	2,968.6
U4 Expired 31-Jan-09	0.0	85.2	0.0	0.0	4,945.0	5,030.2
V1 Expired 30-Apr-09	0.0	197.9	0.0	0.0	2,572.8	2,770.7
V2 Expired 31-Jul-09	0.0	989.9	16.1	0.0	3,625.1	4,631.1
V3 Expired 31-Oct-09	0.0	1,132.0	0.0	0.0	3,822.7	4,954.7
V4 Expired 31-Jan-10	0.0	748.8	0.0	0.0	3,708.0	4,456.8
W1 Expired 30-Apr-10	0.0	567.4	0.0	0.0	5,139.5	5,706.9
W2 Expired 31-Jul-10	0.0	351.7	0.0	0.0	3,051.7	3,403.4
W3 Expired 31-Oct-10	0.0	508.7	0.0	0.0	8,695.9	9,204.6
W4 Expired 31-Jan-11	0.0	1,415.8	0.0	0.0	4,152.6	5,568.4
X1 Expired 30-Apr-11	0.0	1,101.7	0.0	0.0	6,200.6	7,302.3
X2 Expired 31-Jul-11	0.0	3,706.4	0.0	0.0	5,578.4	9,284.7
X3 Expired 31-Oct-11	0.0	109.2	0.0	0.0	7,665.9	7,775.1
X4 Expired 31-Jan-12	0.0	2,948.9	0.0	0.0	2,419.4	5,368.3
Y1 Expired 30-Apr-12	0.0	1,795.5	0.0	0.0	6,279.7	8,075.2
Y2 Expired 31-Oct-12	0.0	1,477.2	0.0	0.0	9,636.5	11,113.7
Y3 Expired 30-Apr-13	0.0	1,630.5	0.0	0.0	4,609.2	6,239.6
Z1 Expired 31-Oct-13	189.0	3,094.5	0.0	675.0	4,055.0	8,013.5
Z2 Expired 30-Apr-14	0.0	3,062.0	0.0	0.0	3,037.8	6,099.8
AA1 Expired 31-Oct-14	553.2	4,678.9	340.0	0.0	6,498.4	12,070.5
AA2 Expired 30-Apr-15	1,549.0	2,819.6	205.0	0.0	11,492.7	16,066.3
AB1 Expired 31-Oct-15	1,267.8	1,478.7	1,348.0	2,700.0	13,649.3	20,443.7
AB2 Expired 31-Mar-16	874.9	2,032.5	1,510.1	129.9	10,608.4	15,155.8
AC1 Expired 30-Sep-16	1,822.2	3,431.7	2,033.0	413.9	12,335.2	20,035.9
AC2 Expired 30-Apr-17	2,178.3	662.0	334.8	186.7	9,207.8	12,569.6
AD1 Expired 30-Sep-17	3,897.6	412.9	363.9	477.5	6,149.7	11,301.6
AD2 Expired 31-Mar-18	4,180.6	503.7	857.2	174.5	14,584.9	20,300.8
AE1 Expired 30-Sep-18	12,356.1	129.5	124.0	1,652.8	19,634.5	33,896.9
AE2 Expired 31-Mar-19	19,208.7	316.0	300.8	570.2	13,431.8	33,827.5
AF1 Expired 30-Sep-19	19,332.9	37.8	61.0	369.6	9,126.7	28,927.9
AF2 Expired 31-Mar-20	20,472.3	85.9	60.2	82.7	7,514.6	28,215.5
AG1 Expired 30-Sep-20	32,159.3	0.5	25.0	15.0	5,908.5	38,108.3
AG2 Expired 31-Mar-21	54,403.9	0.0	1.0	3.0	2,341.4	56,749.3
AH1 Expired 10-Sep-21	45,621.2	0.0	0.0	0.0	4,337.3	49,958.6
AH2 Expired 10-Mar-22	27,482.2	0.0	0.0	0.0	6,846.8	34,329.0
AI1 Expired 10-Sep-22	21,968.2	0.0	0.0	0.0	1,539.8	23,508.0
AI2 Expired 10-Mar-23	3,539.5	0.0	0.0	0.0	0.0	3,539.5
Total	273,127.0	81,630.1	7,580.0	7,450.7	451,340.4	821,128.2

51 Projects listed as partially in service are counted as in service for the purposes of this analysis.

Table 12-19 shows the projects with a status of active, suspended or under construction, by unit type, and control zone. As of March 31, 2023, 288,157.8 MW were in generation request queues for construction through 2029. Table 12-19 also shows the planned retirements for each zone.

Table 12-19 Queue totals for projects (active, suspended and under construction) by LDA, control zone and unit type (MW): March 31, 2023[52]

LDA	Zone	Battery	CC	CT - Natural Gas	CT - Oil	CT - Other	Fuel Cell	Hydro - Pumped Storage	Hydro - Run of River	Nuclear	RICE - Natural Gas	RICE - Oil	RICE - Other	Solar	Solar + Storage	Solar + Wind	Steam - Coal	Steam - Natural Gas	Steam - Oil	Steam - Other	Wind	Wind + Storage	Total Queue Capacity	Planned Retirements
EMAAC	ACEC	2,039.5	0.0	230.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	668.3	221.0	0.0	0.0	0.0	0.0	0.0	3,141.6	0.0	6,300.4	149.2
	DPL	1,064.0	451.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2,323.0	270.0	0.0	0.0	0.0	0.0	0.0	7,369.5	0.0	11,477.5	578.9
	JCPLC	1,536.8	0.0	0.0	0.0	0.0	0.0	30.0	0.0	0.0	0.0	0.0	0.0	696.4	215.0	0.0	0.0	0.0	0.0	0.0	12,909.2	0.0	15,387.4	0.0
	PECO	0.0	5.0	0.0	0.0	0.0	0.0	0.0	0.0	44.0	0.0	0.0	0.0	129.4	5.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	183.4	0.0
	PSEG	1,782.0	51.1	675.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	59.2	22.6	0.0	0.0	5.0	0.0	0.0	2,610.0	0.0	5,204.9	0.0
	REC	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	EMAAC Total	6,422.3	507.1	905.0	0.0	0.0	0.0	30.0	0.0	44.0	0.0	0.0	0.0	3,876.3	733.6	0.0	0.0	5.0	0.0	0.0	26,030.3	0.0	38,553.5	728.1
SWMAAC	BGE	1,458.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	154.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1,613.4	0.0
	PEPCO	796.0	45.0	42.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	238.2	1,452.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2,573.5	0.0
	SWMAAC Total	2,254.5	45.0	42.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	393.1	1,452.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	4,186.9	0.0
WMAAC	MEC	955.2	75.0	11.5	7.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	846.1	282.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2,177.5	0.0
	PE	1,267.8	115.0	585.5	0.0	3.6	3.0	0.0	0.0	0.0	0.0	0.0	0.0	6,165.0	1,486.6	0.0	0.0	0.0	0.0	0.0	574.3	0.0	10,200.8	0.0
	PPL	435.0	51.6	0.0	0.0	0.0	0.0	700.0	0.0	0.0	0.0	0.0	0.0	2,663.7	750.0	0.0	0.0	0.0	0.0	0.0	174.8	90.0	4,865.1	52.6
	WMAAC Total	2,658.0	241.6	597.0	7.5	3.6	3.0	700.0	0.0	0.0	0.0	0.0	0.0	9,674.8	2,518.8	0.0	0.0	0.0	0.0	0.0	749.1	90.0	17,243.4	52.6
Non-MAAC	AEP	11,225.9	3,360.0	791.0	0.0	40.1	0.0	0.0	51.0	0.0	0.0	0.0	0.0	44,073.5	15,627.8	0.0	65.0	0.0	0.0	0.0	2,981.0	0.0	78,215.2	80.0
	AMPT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	206.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	206.0	0.0
	APS	3,480.8	4,700.0	30.0	0.0	0.0	0.0	0.0	15.0	0.0	14.4	0.0	0.0	6,683.5	3,097.3	0.0	0.0	0.0	0.0	0.0	1,029.1	0.0	19,050.1	1,278.0
	ATSI	2,418.0	1,953.0	463.7	1.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	6,878.0	741.6	0.0	0.0	0.0	0.0	0.0	297.7	0.0	12,753.5	1,522.2
	COMED	8,536.1	1,836.7	964.2	0.0	0.0	5.0	0.0	0.0	0.0	0.0	0.0	0.0	14,103.9	2,999.5	199.0	0.0	0.0	0.0	0.0	9,604.1	0.0	38,248.5	1,326.0
	DAY	340.0	0.0	20.0	0.0	10.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	3,558.4	650.8	0.0	0.0	0.0	0.0	0.0	100.0	0.0	4,679.3	0.0
	DUKE	527.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	678.9	40.0	10.0	0.0	0.0	0.0	0.0	0.0	0.0	1,256.1	0.0
	DLCO	505.0	0.0	0.0	0.0	0.0	0.0	0.0	46.8	0.0	0.0	0.0	0.0	88.9	107.5	0.0	0.0	0.0	0.0	20.0	0.0	0.0	768.2	0.0
	DOM	15,878.2	118.0	1,138.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	32,195.9	8,117.1	0.0	0.0	0.0	0.0	0.0	5,307.5	150.0	62,904.7	1,877.0
	EKPC	176.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	6,094.0	3,214.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	9,484.1	0.0
	OVEC	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	430.0	178.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	608.5	0.0
	RMU	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Non-MAAC Total	43,087.2	11,967.7	3,406.9	1.5	50.2	5.0	0.0	112.8	0.0	14.4	0.0	0.0	114,991.0	34,774.0	209.0	65.0	0.0	0.0	20.0	19,319.3	150.0	228,174.0	6,083.2
Total		54,422.0	12,761.4	4,951.2	9.0	53.8	8.0	730.0	112.8	44.0	14.4	0.0	0.0	128,935.2	39,478.4	209.0	65.0	5.0	0.0	20.0	46,098.7	240.0	288,157.8	6,863.9

Since wind resources cannot be dispatched on demand, PJM rules previously required that the unforced capacity of wind resources be derated to 20 percent of nameplate capacity until actual generation data are available. Beginning with Queue U, PJM derated wind resources to 13 percent of nameplate capacity until there was operational data to support a different conclusion.[53] PJM derated solar resources to 38 percent of nameplate capacity. Effective June 1, 2017, PJM adjusted the derates of wind and solar resources. The capacity factor derates for wind resources are dependent on the wind farm locations and have an average derate of 16.2 percent. The capacity factor derates for solar resources are dependent on the solar installation type and have an average derate of 46.7 percent.

Beginning with the 2023/2024 Delivery Year, unforced capacity for intermittent resources and limited duration resources will be determined by PJM's effective load carrying capability (ELCC) analysis. The PJM ELCC analysis will determine capacity derates by resource class. The unforced capacity derate for a specific resource will equal the product of the ELCC class rating and a resource specific performance factor. The 2023/2024 ELCC class rating for wind resources is 15.0 percent, for solar resources with tracking panels is 54.0 percent and for solar resources with fixed panels is 38.0 percent.[54] The ELCC class rating for battery or energy storage resources replaces the 10 hour rule that was previously used to determine the unforced capacity value for an energy storage resource. PJM

52 This data includes only projects with a status of active, under construction, or suspended.
53 See "PJM Manual 14B: PJM Region Transmission Planning Process," Rev. 51 (December 15, 2021).
54 *ELCC Class Ratings for 2023-2024 BRA*, PJM Interconnection L.L.C. (December 16, 2021) <https://www.pjm.com/planning/resource-adequacy-planning/effective-load-carrying-capability>

defined four different energy storage classes differentiated by duration. The ELCC class rating is 83.0 percent for storage resources that can continuously generate energy at the nameplate capacity for four hours (four hour storage). The ELCC class rating is 98.0 percent for six hour storage and 100 percent for 8 hour storage and 10 hour storage.[55] Using the ELCC derate factors, based on the derating of 46,098.7 MW of wind resources to 6,914.8 MW, 128,935.2 MW of solar resources to 69,625.0 MW, 39,478.4 MW of solar + storage resources to 21,318.3 MW, 209.0 MW of solar + wind resources to 112.9 MW, 240.0 MW of wind + storage resources to 36.0 MW and 54,422.0 MW of battery resources to 45,170.3 MW, the 288,157.8 MW currently under construction, suspended or active in the queue would be reduced to 161,951.8 MW.[56]

Withdrawn Projects

The queue contains a substantial number of projects that are not likely to be built. The queue process results in a substantial number of projects that are withdrawn. Manual 14B requires PJM to apply a commercial probability factor at the feasibility study stage to improve the accuracy of capacity and cost estimates. The commercial probability factor is based on the historical incidence of projects dropping out of the queue at the impact study stage, but the actual calculation of commercial probability factors is less than transparent.[57] The impact and facilities studies are performed using the full amount of planned generation in the queues. The actual withdrawal rates are shown in Table 12-20 and Table 12-21.

Table 12-20 shows the milestone status when projects were withdrawn, for all withdrawn projects. Of the 3,499 projects withdrawn as of March 31, 2023, 1,745 (49.9 percent) were withdrawn before the system impact study was completed. Once a Construction Service Agreement (CSA) is executed, the financial obligation for any necessary transmission upgrades cannot be retracted. Of the 3,499 projects withdrawn, 660 (18.9 percent) were withdrawn after the completion of a Construction Service Agreement.

55 Additional information available in *PJM Manual 21A: Determination of Accredited UCAP Using Effective Load Carrying Capability Analysis*, PJM Interconnection L.L.C., Rev. 1 (May 25, 2022).

56 The ELCC derate adjusted MW are calculated using the four hour storage ELCC derate of 83.0 percent for battery resources, 15.0 percent ELCC derate for wind resources and 54.0 percent ELCC derate for solar resources.

57 See "PJM Manual 14B: PJM Region Transmission Planning Process," Rev. 51 (December 15, 2021).

Table 12-20 Last milestone at time of withdrawal: January 1, 1997 through March 31, 2023

Milestone Completed	Projects Withdrawn	Percent	Average Days	Maximum Days
Never Started	706	20.2%	248	1,193
Feasibility Study	1,039	29.7%	270	1,633
System Impact Study	770	22.0%	729	3,248
Facilities Study	324	9.3%	1,155	4,107
Construction Service Agreement (CSA) or beyond	660	18.9%	1,391	7,864
Total	3,499	100.0%		

Average Time in Queue

Table 12-21 shows the time spent at various stages in the queue process and the completion time for the studies performed. For completed projects, there is an average time of 1,127 days, or 3.1 years, between entering a queue and going into service. For withdrawn projects, there is an average time of 644 days, or 1.8 years, between entering a queue and withdrawing.

Table 12-21 Project queue times by status (days): March 31, 2023[58]

Status	Average (Days)	Standard Deviation	Maximum
Active	830	510	5,856
In-Service	1,127	798	5,306
Suspended	1,643	586	3,438
Under Construction	1,942	667	5,054
Withdrawn	644	748	7,864

58 The queue data shows that some projects were withdrawn and a withdrawal date was not identified. These projects were removed for the purposes of this analysis.

Table 12-22 presents information on the time in the stages of the queue for those projects not yet in service or already withdrawn. Of the 3,332 projects in the queue as of March 31, 2023, 175 (5.3 percent) had a completed feasibility study and 529 (15.9 percent) had a completed construction service agreement.

Table 12-22 Project queue times by milestone (days): March 31, 2023

Milestone Reached	Number of Projects	Percent of Total Projects	Average Days	Maximum Days
Under Review	1,913	57.4%	1,271	1,703
Feasibility Study	175	5.3%	961	1,372
System Impact Study	667	20.0%	1,175	1,842
Facilities Study	48	1.4%	1,646	2,194
Construction Service Agreement (CSA) or beyond	529	15.9%	1,745	5,856
Total	3,332	100.0%		

Table 12-23 shows the time spent in the queue by fuel type, and year the project entered the queue, for projects that are in service. The time from when a project enters the queue to the time the project goes in service has generally been decreasing compared to the period prior to 2017 although there are significant exceptions. For example, for a battery project entering the queue in 2015, there was an average of 1,082 days from the time it entered the queue until it went in service, compared to only 293 days when entering the queue in 2018, but the time increased to 600 days for battery projects entering the queue in 2019.

Table 12-23 Average time in queue (days) by fuel type and year submitted (In Service Projects): March 31, 2023[59]

Unit Type	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Battery	983	609	417	692	789	1,082	941		293	600	544			
CC	1,310	1,551	1,663	1,419	1,175	1,125	1,017	1,047	309	512				
CT - Natural Gas	1,131	804	953	1,073	734	619	1,404	1,038	805	395	560			
CT - Oil	717		259							280				
CT - Other	729	634	954	1,248	718	360								
Fuel Cell						827	643							
Hydro - Pumped Storage						1,402								
Hydro - Run of River			1,325	614	332		580	426	606					
Nuclear	885	866		1,234			2,409	1,100	1,747					
RICE - Natural Gas			1,702	1,053	1,332	798		250						
RICE - Oil						1,849								
RICE - Other	638	1,385	1,479	241	627	622	491		466					
Solar	1,701	1,395	969	1,014	1,003	1,624	1,444	1,141	892	737	556			
Solar + Storage									553					
Solar + Wind														
Steam - Coal	745		513	1,010	583	853	684	647	1,122					
Steam - Natural Gas				1,182		421	751							
Steam - Oil														
Steam - Other	256	838	643											
WInd	2,748	2,711	1,750	1,589	1,205	1,463	1,443	1,398	934		884			
Wind + Storage							1,189							

59 A blank cell in this table means that no project of that fuel type, which was submitted to the queue in that year, subsequently went in service.

Completion Rates

The probability of a project going into service increases as each step of the planning process is completed. Table 12-24 shows the historic completion rates (MW energy) by unit type for projects that have completed the system impact study (SIS), facilities study agreement (FSA) and any milestone completed beyond the FSA including a Construction Service Agreement (CSA), Interconnection Service Agreement (ISA), Upgrade Construction Service Agreement (UCSA) and Wholesale Market Participant Agreement (WMPA) as well as the historic completion rates for all projects including those withdrawn before reaching the SIS milestone.[60] For each unit type, the total MW in service was divided by the total energy MW entered in the queue. To calculate the completion rates for projects that reached the individual milestones, only those projects that reached a final status of withdrawn or in service were evaluated. For example, if a project was withdrawn after the completion of its SIS, but before the completion of the FSA, the totals would be included in the calculation of the SIS completion rate, but not in the calculation of the FSA or CSA completion rates. Similarly, if a project was withdrawn after the completion of its FSA, but before the completion of the CSA, the totals would be included in the calculation of the SIS and FSA completion rates, but not in the calculation of the CSA completion rate. The completion rates show that of all battery projects to ever enter the queue and complete the system impact study stage, 11.1 percent of the queued MW have gone into service. The completion rate for battery projects increases to 30.1 percent when battery projects complete the facility study agreement and further increases to 37.7 percent when battery projects complete the construction service agreement. Of all battery projects to enter the queue, only 0.4 percent of the queued MW have gone into service.

60 All milestones after the FSA are included in the totals under the CSA headings of the tables within Section 12, "Generation and Transmission Planning."

Table 12-24 Historic completion rates (MW energy) by unit type for projects with a completed SIS, FSA and CSA: March 31, 2023

Unit Type	Completion Rate (SIS)	Completion Rate (FSA)	Completion Rate (CSA)	Completion Rate (ALL)
Battery	11.1%	30.1%	37.7%	0.4%
CC	32.9%	49.3%	73.2%	15.9%
CT - Natural Gas	65.6%	79.9%	84.1%	43.7%
CT - Oil	35.4%	59.7%	90.8%	25.4%
CT - Other	12.1%	18.4%	29.5%	8.4%
Fuel Cell	30.6%	31.6%	31.6%	30.2%
Hydro - Pumped Storage	100.0%	100.0%	100.0%	24.1%
Hydro - Run of River	42.5%	60.0%	67.2%	20.9%
Nuclear	34.7%	41.9%	51.3%	28.5%
RICE - Natural Gas	30.7%	42.8%	47.4%	25.9%
RICE - Oil	34.0%	59.7%	59.7%	24.6%
RICE - Other	89.0%	91.4%	92.0%	78.1%
Solar	21.3%	45.7%	56.8%	3.0%
Solar + Storage	0.0%	0.2%	0.4%	0.0%
Solar + Wind	0.0%	0.0%	0.0%	0.0%
Steam - Coal	13.7%	25.5%	37.6%	6.3%
Steam - Natural Gas	90.5%	91.1%	91.1%	90.0%
Steam - Oil	0.0%	0.0%	0.0%	0.0%
Steam - Other	30.4%	39.9%	47.8%	27.1%
Wind	0.2%	100.0%	100.0%	0.0%
Wind + Storage	0.0%	0.0%	0.0%	0.0%

On March 31, 2023, 288,157.8 MW were in generation request queues in the status of active, under construction or suspended. Of the total 288,157.8 MW in the queue, 174,476.9 MW (60.5 percent) have reached at least the SIS milestone and 113,680.9 MW (39.5 percent) have not received a completed SIS. Based on historical completion rates, (applying the unit type specific completion rates for those projects that have reached the SIS, FSA or any milestone beyond the FSA, and using the overall completion rates for those projects that have not yet reached the SIS milestone), 42,640.7 MW (14.8 percent) of new generation in the queue are expected to go into service.

Table 12-25 shows the percent of all project MW, by unit type, to go in service by year submitted to the queue. Of all battery projects that entered the queue in 2010, 65.5 percent reached the status of in service by March 31, 2023. Of all battery projects that entered the queue in 2016, only 1.3 percent have reached the status of in service as of March 31, 2023.

Table 12-25 Percent of all projects (MW energy) to go in service by unit type and year submitted to the queue: March 31, 2023

Unit Type	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Battery	65.5%	8.3%	15.1%	43.9%	21.5%	7.7%	1.3%	0.0%	0.3%	0.0%	0.0%	0.0%	0.0%	0.0%
CC	14.6%	24.5%	30.8%	35.6%	53.6%	9.2%	11.7%	7.1%	1.2%	0.5%	0.0%	0.0%	0.0%	NA
CT - Natural Gas	100.0%	98.3%	71.6%	42.2%	32.0%	0.2%	11.1%	32.3%	7.4%	2.5%	6.4%	0.0%	0.0%	NA
CT - Oil	100.0%	NA	1.2%	0.0%	0.0%	NA	NA	NA	0.0%	30.8%	0.0%	NA	NA	NA
CT - Other	28.8%	26.2%	36.1%	100.0%	0.0%	100.0%	NA	0.0%	NA	NA	NA	0.0%	NA	NA
Fuel Cell	NA	NA	NA	NA	NA	67.4%	12.5%	0.0%	NA	0.0%	NA	0.0%	NA	NA
Hydro - Pumped Storage	NA	NA	NA	NA	NA	100.0%	NA	NA	0.0%	0.0%	NA	0.0%	NA	NA
Hydro - Run of River	0.0%	0.0%	57.6%	49.6%	11.2%	NA	100.0%	26.8%	100.0%	0.0%	0.0%	0.0%	NA	NA
Nuclear	15.5%	1.6%	0.0%	100.0%	NA	NA	25.4%	100.0%	100.0%	NA	0.0%	NA	NA	NA
RICE - Natural Gas	NA	NA	100.0%	66.7%	5.4%	6.2%	0.0%	5.4%	NA	NA	NA	0.0%	NA	NA
RICE - Oil	0.0%	0.0%	NA	NA	NA	30.8%	NA	NA	NA	NA	NA	NA	0.0%	NA
RICE - Other	100.0%	100.0%	100.0%	100.0%	79.7%	25.5%	2.8%	0.0%	100.0%	NA	NA	NA	NA	NA
Solar	10.7%	8.1%	16.9%	24.4%	30.7%	23.9%	22.0%	2.2%	0.6%	1.0%	0.1%	0.0%	0.0%	0.0%
Solar + Storage	NA	NA	NA	NA	NA	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Solar + Wind	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	0.0%	0.0%	NA	NA
Steam - Coal	100.0%	0.0%	1.4%	68.4%	1.2%	23.4%	37.5%	100.0%	22.4%	0.0%	NA	NA	NA	NA
Steam - Natural Gas	NA	NA	NA	100.0%	0.0%	100.0%	100.0%	100.0%	NA	NA	0.0%	NA	NA	NA
Steam - Oil	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Steam - Other	0.5%	61.2%	16.6%	0.0%	0.0%	NA	NA	NA	NA	NA	NA	0.0%	NA	NA
WInd	6.1%	3.4%	2.5%	6.3%	20.7%	12.5%	12.3%	2.6%	0.6%	0.0%	0.0%	0.0%	0.0%	0.0%
Wind + Storage	NA	NA	NA	NA	NA	NA	100.0%	0.0%	NA	NA	NA	NA	0.0%	NA
All	11.7%	19.0%	25.9%	34.5%	40.3%	11.9%	15.3%	4.4%	1.1%	0.5%	0.1%	0.0%	0.0%	0.0%

Table 12-26 shows the total MW that went in service each year, by unit type, since 1999. In the first three months of 2023, 161.1 MW from the queue went in service. Of the 161.1 MW that went in service, 55.0 MW (34.1 percent) were combined cycle units, 55.0 MW (34.1 percent) were solar units and 51.1 MW (31.7 percent) were combustion turbine natural gas units.

Table 12-26 Total (MW Energy) by unit type and year project went in service: March 31, 2023

Unit Type	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Battery	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	27.4	4.5	23.0	24.0	110.4	10.0	2.0	40.0	25.5	0.0	1.5	0.0	0.0
CC	0.0	0.0	100.0	2,608.0	2,785.0	2,845.0	15.1	1,196.0	22.0	177.0	52.0	136.0	1,869.0	162.7	82.2	2,155.7	2,977.7	5,418.0	3,888.1	10,865.0	2,881.4	88.0	3,424.7	1,200.9	55.0
CT - Natural Gas	0.0	401.6	432.0	2,442.0	638.7	61.3	993.0	39.3	97.0	821.0	181.7	97.8	850.4	393.0	95.0	125.2	317.9	72.0	212.0	388.0	104.0	127.0	328.4	153.5	51.1
CT - Oil	0.0	0.0	315.0	6.5	0.0	33.0	292.0	7.5	21.0	15.3	85.6	0.0	23.9	2.0	0.5	2.0	0.0	0.0	0.0	0.0	0.0	4.0	0.0	0.0	0.0
CT - Other	0.0	0.0	10.0	0.0	0.0	4.1	0.0	0.0	11.0	6.9	0.0	18.2	0.0	70.7	17.6	6.0	8.0	5.9	0.0	0.0	3.2	0.0	0.0	0.0	0.0
Fuel Cell	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.9	0.0	0.0	0.0	0.0	0.0
Hydro - Pumped Storage	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	340.0	16.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	34.0	0.0	0.0	0.0	0.0	0.0
Hydro - Run of River	0.0	0.0	0.0	107.0	196.0	2.0	0.0	5.7	2.5	0.0	6.2	180.0	27.0	0.0	6.0	28.9	160.5	0.0	29.5	5.5	0.0	2.4	0.0	0.0	0.0
Nuclear	54.2	0.0	165.0	15.0	44.0	0.0	1,693.0	242.0	130.0	115.0	0.0	281.0	422.0	328.0	117.0	80.0	54.0	133.8	130.0	0.0	0.0	0.0	0.0	0.0	0.0
RICE - Natural Gas	0.0	0.0	0.0	0.0	0.0	8.0	29.0	2.0	19.5	0.0	0.0	10.5	0.0	0.0	0.0	0.0	18.9	20.9	19.9	5.2	39.8	0.0	0.0	0.0	0.0
RICE - Oil	0.0	0.0	0.0	0.0	0.0	23.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	4.0	0.0	0.0	0.0
RICE - Other	0.0	1.2	0.0	2.9	17.2	0.0	27.5	44.9	86.6	57.6	38.8	13.8	43.0	2.0	109.0	0.0	3.8	19.3	22.4	0.0	0.8	0.0	0.0	0.0	0.0
Solar	69.8	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	3.3	5.1	6.8	137.2	98.9	44.4	59.8	172.1	300.8	332.9	285.3	559.0	1,660.0	807.5	666.2	55.0
Solar + Storage	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.1	0.0	0.0	0.0	0.0
Solar + Wind	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Steam - Coal	12.0	20.0	59.0	21.0	0.0	37.0	20.0	14.0	55.0	718.0	123.0	177.0	97.0	708.0	48.0	16.0	92.5	0.0	47.0	24.0	20.0	0.0	11.0	0.0	0.0
Steam - Natural Gas	0.0	0.0	2.5	10.0	0.0	0.0	0.0	0.0	25.0	145.0	0.0	0.0	5.5	0.0	0.0	0.0	0.0	696.5	0.0	0.0	0.0	64.0	0.0	0.0	0.0
Steam - Oil	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Steam - Other	0.0	0.0	0.0	0.0	0.0	0.0	0.0	529.0	0.0	22.5	0.0	122.5	0.9	0.0	50.0	3.8	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
WInd	0.0	0.0	0.0	15.0	190.0	20.4	7.5	380.0	1,053.3	729.8	622.0	1,183.5	326.6	1,424.5	150.0	500.0	455.0	465.8	700.7	762.0	535.0	1,008.6	310.0	0.0	0.0
Wind + Storage	16.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total	152.3	422.8	1,083.5	5,227.4	3,870.9	3,034.1	3,077.1	2,460.4	1,522.9	2,811.4	1,454.4	2,243.1	3,829.8	3,194.2	742.7	3,001.4	4,370.8	7,143.0	5,384.5	12,410.9	4,169.8	2,958.0	4,883.1	2,020.6	161.1

Queue Analysis by Fuel Group

The time it takes to complete a study depends on the backlog and the number of projects in the queue, but not on the size of the project. Table 12-27 shows the number of projects that entered the queue by year and by fuel group. The fuel groups are nuclear units, renewable units (including solar, hydro, biomass, renewable hybrid and wind) and traditional units (all other fuels). The number of queue entries has increased during the past several years, primarily by renewable projects. Of the 5,249 projects entered from January 2015 through March 2023, 3,915 projects (74.6 percent) were renewable. Of the 181 projects entered in the first three months of 2023, 164 projects (90.6 percent) were renewable.

Table 12-27 Number of projects entered in the queue: March 31, 2023

	Fuel Group						
Year Entered	Nuclear	Percent Nuclear	Renewable	Percent Renewable	Traditional	Percent Traditional	Total
1997	2	15.38%	0	0.00%	11	84.62%	13
1998	0	0.00%	0	0.00%	18	100.00%	18
1999	1	1.11%	5	5.56%	84	93.33%	90
2000	2	2.41%	3	3.61%	78	93.98%	83
2001	4	4.40%	6	6.59%	81	89.01%	91
2002	3	5.88%	15	29.41%	33	64.71%	51
2003	1	1.89%	34	64.15%	18	33.96%	53
2004	4	7.41%	17	31.48%	33	61.11%	54
2005	3	2.26%	75	56.39%	55	41.35%	133
2006	9	5.73%	67	42.68%	81	51.59%	157
2007	9	4.11%	65	29.68%	145	66.21%	219
2008	3	1.39%	102	47.22%	111	51.39%	216
2009	10	5.78%	107	61.85%	56	32.37%	173
2010	5	1.13%	370	83.90%	66	14.97%	441
2011	6	1.69%	264	74.37%	85	23.94%	355
2012	2	1.26%	59	37.11%	98	61.64%	159
2013	1	0.65%	54	35.06%	99	64.29%	154
2014	0	0.00%	100	52.08%	92	47.92%	192
2015	0	0.00%	134	43.37%	175	56.63%	309
2016	2	0.50%	298	74.69%	99	24.81%	399
2017	2	0.56%	293	82.54%	60	16.90%	355
2018	1	0.23%	344	78.18%	95	21.59%	440
2019	0	0.00%	547	78.48%	150	21.52%	697
2020	2	0.20%	782	78.44%	213	21.36%	997
2021	0	0.00%	984	73.71%	351	26.29%	1,335
2022	0	0.00%	369	68.84%	167	31.16%	536
2023	0	0.00%	164	90.61%	17	9.39%	181
Total	72	0.91%	5,258	66.55%	2,571	32.54%	7,901

As of March 31, 2023, renewable projects make up 76.3 percent of all projects in the queue and those projects account for 74.9 percent of the nameplate MW currently active, suspended or under construction in the queue as of March 31, 2023 (Table 12-28).

Table 12-28 Queue details by fuel group: March 31, 2023

Fuel Group	Number of Projects	Percent of Projects	MW	Percent MW
Nuclear	1	0.0%	44.0	0.0%
Renewable	2,542	76.3%	215,812.0	74.9%
Traditional	789	23.7%	72,301.8	25.1%
Total	3,332	100.0%	288,157.8	100.0%

Historical completion rates for renewable projects may not be an accurate predictor of completion rates for current renewable projects. The outcomes for current projects will provide additional information and improve the ability to assess the likely future generation mix based on the type of projects in the queue.

While renewables currently make up the majority of both projects and nameplate MW in the queue, historical completion rates and derating factors must be accounted for when evaluating the share of capacity resources that are likely to be contributed by renewables (Table 12-24). Table 12-29 shows the total MW of all projects in the queue as of March 31, 2023, in the status of active, suspended and under construction, by unit type. Table 12-29 also shows the total MW for each fuel type adjusted based on current historical completion rates and for battery, solar and wind ELCC derates. Of the 12,761.4 MW of combined cycle projects in the queue, 7,902.6 MW (61.9 percent) are expected to go in service based on historical completion rates as of March 31, 2023. Of the 215,812.0 MW of renewable projects in the queue, only 29,880.4 MW (13.9 percent) are expected to go in service based on historical completion rates. Of the 215,812.0 MW of renewable projects in the queue, only 13,592.2 MW (6.3 percent) of capacity resources are expected to go into service, based on both historical completion rates and ELCC derate factors for battery, wind and solar.

Table 12-29 Queue totals for projects (active, suspended and under construction) by unit type adjusted based on current historical completion rates and ELCC battery, solar and wind derates (MW): March 31, 2023[61]

Unit Type	MW in Queue	Completion Rate Adjusted MW in Queue	Completion Rate and ELCC Adjusted MW in Queue
Battery	54,422.0	1,417.3	1,176.4
CC	12,761.4	7,902.6	7,902.6
CT - Natural Gas	4,951.2	3,368.2	3,368.2
CT - Oil	9.0	8.2	8.2
CT - Other	53.8	4.5	4.5
Fuel Cell	8.0	2.5	2.5
Hydro - Pumped Storage	730.0	707.2	707.2
Hydro - Run of River	112.8	52.3	52.3
Nuclear	44.0	22.6	22.6
RICE - Natural Gas	14.4	3.7	3.7
RICE - Oil	0.0	0.0	0.0
RICE - Other	0.0	0.0	0.0
Solar	128,935.2	21,692.7	11,714.0
Solar + Storage	39,478.4	6.0	3.2
Solar + Wind	209.0	0.0	0.0
Steam - Coal	65.0	23.1	23.1
Steam - Natural Gas	5.0	4.6	4.6
Steam - Oil	0.0	0.0	0.0
Steam - Other	20.0	5.4	5.4
Wind	46,098.7	7,419.8	1,113.0
Wind + Storage	240.0	0.0	0.0
Total	288,157.8	42,640.7	26,111.5

Queue Analysis by Unit Type and Project Classification

Table 12-30 shows the current status of all generation queue projects by unit type and project classification from January 1, 1997, through March 31, 2023. As of March 31, 2023, 7,901 projects, representing 821,128.2 MW, have entered the queue process since its inception. Of those, 1,070 projects, representing 81,630.1 MW, went into service. Of the projects that entered the queue process, 3,499 projects, representing 451,340.4 MW (55.0 percent of the MW) withdrew prior to completion. Such projects may create barriers to entry for projects that would otherwise be completed by taking up queue positions, increasing interconnection costs and creating uncertainty.

61 The derate adjusted MW in this table are calculated using the four hour storage ELCC derate of 83.0 percent for battery resources, 15.0 percent ELCC derate for wind resources and 54.0 percent ELCC derate for solar resources.

A total of 6,183 projects have been classified as new generation and 1,718 projects have been classified as upgrades. Natural gas, wind, solar and renewable hybrid projects (including solar + storage, solar + wind and wind + storage) have accounted for 6,191 projects (78.4 percent) of all 7,901 generation queue projects to enter the queue since January 1, 1997.

Table 12-30 Status of all generation queue projects: January 1, 1997 through March 31, 2023

		Number of Projects																					
Project Status	Project Classification	Battery	CC	CT - Natural Gas	CT - Oil	CT - Other	Fuel Cell	Hydro - Pumped Storage	Hydro - Run of River	Nuclear	RICE - Natural Gas	RICE - Oil	RICE - Other	Solar	Solar + Storage	Solar + Wind	Steam - Coal	Steam - Natural Gas	Steam - Oil	Steam - Other	Wind	Wind + Storage	Total
In Service	New Generation	23	65	49	10	25	3	0	10	2	10	0	55	211	1	0	8	5	0	4	98	0	579
	Upgrade	7	110	123	16	5	0	3	19	45	9	2	16	46	0	0	56	10	0	8	15	1	491
Under Construction	New Generation	4	2	2	0	0	0	0	0	0	0	0	0	48	3	0	0	1	0	0	1	0	61
	Upgrade	0	7	11	7	0	1	0	0	1	0	0	0	13	1	0	1	0	0	0	3	0	45
Suspended	New Generation	3	5	1	0	0	0	0	0	0	0	0	0	49	17	0	0	0	0	0	0	1	76
	Upgrade	0	0	0	0	0	0	0	0	0	0	0	0	3	1	0	0	0	0	0	0	0	4
Withdrawn	New Generation	223	436	29	10	83	26	2	44	9	29	12	16	1,541	100	0	55	1	0	34	474	0	3,124
	Upgrade	64	102	19	15	13	2	0	5	15	0	3	3	82	2	0	15	2	0	2	31	0	375
Active	New Generation	421	5	5	0	5	0	2	5	0	1	0	0	1,417	381	2	0	0	0	1	97	1	2,343
	Upgrade	263	20	20	0	2	2	1	2	0	0	0	0	387	46	1	2	0	0	0	56	1	803
Total Projects	New Generation	674	513	86	20	113	29	4	59	11	40	12	71	3,266	502	2	63	7	0	39	670	2	6,183
	Upgrade	334	239	173	38	20	5	4	26	61	9	5	19	531	50	1	74	12	0	10	105	2	1,718

Table 12-31 shows the totals in Table 12-30 by share of classification as new generation or upgrade. Within a unit type the shares of upgrades add to 100 percent and the shares of new generation add to 100 percent. For example, 70.9 percent of all hydro run of river projects classified as upgrades are currently in service in PJM, 19.2 percent of hydro run of river upgrades were withdrawn and 9.9 percent of hydro run of river upgrades are active in the queue.

Table 12-31 Status of all generation queue projects as a percent of total projects by classification: January 1, 1997 through March 31, 2023

		Percent of Projects																					
Project Status	Project Classification	Battery	CC	CT - Natural Gas	CT - Oil	CT - Other	Fuel Cell	Hydro - Pumped Storage	Hydro - Run of River	Nuclear	RICE - Natural Gas	RICE - Oil	RICE - Other	Solar	Solar + Storage	Solar + Wind	Steam - Coal	Steam - Natural Gas	Steam - Oil	Steam - Other	Wind	Wind + Storage	Total
In Service	New Generation	3.4%	12.7%	57.0%	50.0%	22.1%	10.3%	0.0%	16.9%	18.2%	25.0%	0.0%	77.5%	6.5%	0.2%	0.0%	12.7%	71.4%	0.0%	10.3%	14.6%	0.0%	9.4%
	Upgrade	2.1%	46.0%	71.1%	42.1%	25.0%	0.0%	75.0%	73.1%	73.8%	100.0%	40.0%	84.2%	8.7%	0.0%	0.0%	75.7%	83.3%	0.0%	80.0%	14.3%	50.0%	28.6%
Under Construction	New Generation	0.6%	0.4%	2.3%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	1.5%	0.6%	0.0%	0.0%	14.3%	0.0%	0.0%	0.1%	0.0%	1.0%
	Upgrade	0.0%	2.9%	6.4%	18.4%	0.0%	20.0%	0.0%	0.0%	1.6%	0.0%	0.0%	0.0%	2.4%	2.0%	0.0%	1.4%	0.0%	0.0%	0.0%	2.9%	0.0%	2.6%
Suspended	New Generation	0.4%	1.0%	1.2%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	1.5%	3.4%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	50.0%	1.2%
	Upgrade	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.6%	2.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.2%
Withdrawn	New Generation	33.1%	85.0%	33.7%	50.0%	73.5%	89.7%	50.0%	74.6%	81.8%	72.5%	100.0%	22.5%	47.2%	19.9%	0.0%	87.3%	14.3%	0.0%	87.2%	70.7%	0.0%	50.5%
	Upgrade	19.2%	42.7%	11.0%	39.5%	65.0%	40.0%	0.0%	19.2%	24.6%	0.0%	60.0%	15.8%	15.4%	4.0%	0.0%	20.3%	16.7%	0.0%	20.0%	29.5%	0.0%	21.8%
Active	New Generation	62.5%	1.0%	5.8%	0.0%	4.4%	0.0%	50.0%	8.5%	0.0%	2.5%	0.0%	0.0%	43.4%	75.9%	100.0%	0.0%	0.0%	0.0%	2.6%	14.5%	50.0%	37.9%
	Upgrade	78.7%	8.4%	11.6%	0.0%	10.0%	40.0%	25.0%	7.7%	0.0%	0.0%	0.0%	0.0%	72.9%	92.0%	100.0%	2.7%	0.0%	0.0%	0.0%	53.3%	50.0%	46.7%

Table 12-32 shows the total MW of projects in the PJM generation queue by unit type and project classification. For example, the 474 new generation wind projects that have been withdrawn from the queue as of March 31, 2023, (as shown in Table 12-30) constitute 87,221.6 MW. The 436 new generation combined cycle projects that have been withdrawn in the same time period constitute 219,816.7 MW.

Table 12-32 Status of all generation (MW) in the generation queue: January 1, 1997 through March 31, 2023

		Project MW																					
Project Status	Project Classification	Battery	CC	CT - Natural Gas	CT - Oil	CT - Other	Fuel Cell	Hydro - Pumped Storage	Hydro - Run of River	Nuclear	RICE - Natural Gas	RICE - Oil	RICE - Other	Solar	Solar + Storage	Solar + Wind	Steam - Coal	Steam - Natural Gas	Steam - Oil	Steam - Other	Wind	Wind + Storage	Total
In Service	New Generation	223.9	37,441.9	6,532.8	676.5	149.2	1.9	0.0	371.5	1,639.0	156.4	0.0	440.1	4,908.6	1.1	0.0	1,343.0	723.0	0.0	60.9	10,601.0	0.0	65,270.9
	Upgrade	44.4	7,562.5	2,890.1	131.8	12.3	0.0	390.0	387.6	2,365.0	17.3	27.3	50.7	355.4	0.0	0.0	976.5	225.5	0.0	667.8	238.7	16.3	16,359.2
Under Construction	New Generation	35.0	2,250.0	208.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	3,146.9	19.6	0.0	0.0	5.0	0.0	0.0	200.0	0.0	5,864.5
	Upgrade	0.0	1,022.7	249.0	9.0	0.0	3.0	0.0	0.0	44.0	0.0	0.0	0.0	261.1	3.2	0.0	36.0	0.0	0.0	0.0	87.6	0.0	1,715.6
Suspended	New Generation	27.0	3,950.0	675.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2,402.4	209.4	0.0	0.0	0.0	0.0	0.0	0.0	90.0	7,353.8
	Upgrade	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	46.9	50.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	96.9
Withdrawn	New Generation	8,435.2	219,816.7	4,426.3	1,735.0	1,583.3	5.5	500.0	2,066.5	8,161.0	481.2	63.9	88.6	50,604.1	9,914.8	0.0	33,511.6	27.0	0.0	1,050.9	87,221.6	0.0	429,693.2
	Upgrade	1,394.6	12,919.0	1,001.0	593.0	72.5	0.9	0.0	105.1	1,066.0	0.0	19.6	10.0	1,890.3	3.7	0.0	885.0	6.0	0.0	37.1	1,643.4	0.0	21,647.2
Active	New Generation	44,076.8	4,171.0	2,531.0	0.0	53.8	0.0	700.0	58.6	0.0	14.4	0.0	0.0	111,840.7	37,661.0	209.0	0.0	0.0	0.0	20.0	41,572.3	150.0	243,058.5
	Upgrade	10,283.2	1,367.7	1,288.2	0.0	0.0	5.0	30.0	54.2	0.0	0.0	0.0	0.0	11,237.1	1,535.3	0.0	29.0	0.0	0.0	0.0	4,238.7	0.0	30,068.5
Total Projects	New Generation	52,797.9	267,629.6	14,373.1	2,411.5	1,786.4	7.4	1,200.0	2,496.5	9,800.0	652.0	63.9	528.7	172,902.8	47,805.8	209.0	34,854.6	755.0	0.0	1,131.8	139,594.9	240.0	751,240.9
	Upgrade	11,722.2	22,871.9	5,428.3	733.8	84.8	8.9	420.0	546.9	3,475.0	17.3	46.9	60.7	13,790.8	1,592.2	0.0	1,926.5	231.5	0.0	704.9	6,208.4	16.3	69,887.4

Table 12-33 shows the MW totals in Table 12-32 by share by classification as new generation or upgrade. Within a unit type the shares of upgrades add to 100 percent and the shares of new generation add to 100 percent. For example, 62.5 percent of wind project MW classified as new generation have been withdrawn from the queue between January 1, 1997, and March 31, 2023.

Table 12-33 Status of all generation queue projects as percent of total MW in project classification: January 1, 1997 through March 31, 2023

		Percent of Total Projects by Classification																					
Project Status	Project Classification	Battery	CC	CT - Natural Gas	CT - Oil	CT - Other	Fuel Cell	Hydro - Pumped Storage	Hydro - Run of River	Nuclear	RICE - Natural Gas	RICE - Oil	RICE - Other	Solar	Solar + Storage	Solar + Wind	Steam - Coal	Steam - Natural Gas	Steam - Oil	Steam - Other	Wind	Wind + Storage	Total
In Service	New Generation	0.4%	14.0%	45.5%	28.1%	8.4%	26.2%	0.0%	14.9%	16.7%	24.0%	0.0%	83.2%	2.8%	0.0%	0.0%	3.9%	95.8%	0.0%	5.4%	7.6%	0.0%	8.7%
	Upgrade	0.4%	33.1%	53.2%	18.0%	14.5%	0.0%	92.9%	70.9%	68.1%	100.0%	58.2%	83.5%	2.6%	0.0%	0.0%	50.7%	97.4%	0.0%	94.7%	3.8%	100.0%	23.4%
Under Construction	New Generation	0.1%	0.8%	1.4%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	1.8%	0.0%	0.0%	0.0%	0.7%	0.0%	0.0%	0.1%	0.0%	0.8%
	Upgrade	0.0%	4.5%	4.6%	1.2%	0.0%	33.5%	0.0%	0.0%	1.3%	0.0%	0.0%	0.0%	1.9%	0.2%	0.0%	1.9%	0.0%	0.0%	0.0%	1.4%	0.0%	2.5%
Suspended	New Generation	0.1%	1.5%	4.7%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	1.4%	0.4%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	37.5%	1.0%
	Upgrade	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.3%	3.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.1%
Withdrawn	New Generation	16.0%	82.1%	30.8%	71.9%	88.6%	73.8%	41.7%	82.8%	83.3%	73.8%	100.0%	16.8%	29.3%	20.7%	0.0%	96.1%	3.6%	0.0%	92.9%	62.5%	0.0%	57.2%
	Upgrade	11.9%	56.5%	18.4%	80.8%	85.5%	10.6%	0.0%	19.2%	30.7%	0.0%	41.8%	16.5%	13.7%	0.2%	0.0%	45.9%	2.6%	0.0%	5.3%	26.5%	0.0%	31.0%
Active	New Generation	83.5%	1.6%	17.6%	0.0%	3.0%	0.0%	58.3%	2.3%	0.0%	2.2%	0.0%	0.0%	64.7%	78.8%	100.0%	0.0%	0.0%	0.0%	1.8%	29.8%	62.5%	32.4%
	Upgrade	87.7%	6.0%	23.7%	0.0%	0.0%	55.9%	7.1%	9.9%	0.0%	0.0%	0.0%	0.0%	81.5%	96.4%	0.0%	1.5%	0.0%	0.0%	0.0%	68.3%	0.0%	43.0%

Table 12-34 shows the project MW that entered the PJM generation queue by unit type and year of entry. Since 2016, 70.3 percent of all new projects entering the generation queue have been combined cycle (10.1 percent), wind (17.2 percent) or solar projects (43.0 percent). Prior to 2015, no renewable hybrid units (solar + storage, solar + wind and wind + storage) entered the queue. In the time period from January 1, 2015 through March 31, 2023, 49,863.3 MW of renewable hybrid units have entered the queue.

Table 12-34 Queue project MW by unit type and queue entry year: January 1, 1997 through March 31, 2023

Year	Battery	CC	CT - Natural Gas	CT - Oil	CT - Other	Fuel Cell	Hydro - Pumped Storage	Hydro - Run of River	Nuclear	RICE - Natural Gas	RICE - Oil	RICE - Other	Solar	Solar + Storage	Solar + Wind	Steam - Coal	Steam - Natural Gas	Steam - Oil	Steam - Other	Wind	Wind + Storage	Total
1997	0.0	4,148.0	321.0	315.0	0.0	0.0	0.0	0.0	50.0	0.0	0.0	0.0	0.0	0.0	0.0	6.0	0.0	0.0	0.0	0.0	0.0	4,840.0
1998	0.0	7,006.0	1,775.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	8,781.0
1999	0.0	29,412.7	2,061.1	0.0	10.0	0.0	0.0	196.0	45.0	0.0	0.0	0.0	0.0	0.0	0.0	47.0	0.0	0.0	525.0	115.4	0.0	32,412.2
2000	0.0	21,144.8	493.6	31.5	8.8	0.0	0.0	0.0	95.0	0.0	0.0	1.2	0.0	0.0	0.0	37.0	2.5	0.0	0.0	95.6	0.0	21,909.9
2001	0.0	25,411.7	264.0	0.0	0.0	0.0	0.0	107.0	90.0	0.0	0.0	15.6	0.0	0.0	0.0	1,244.6	10.0	0.0	0.0	234.9	0.0	27,377.8
2002	0.0	4,154.0	11.7	0.0	70.5	0.0	0.0	293.0	236.0	8.0	23.3	4.5	0.0	0.0	0.0	1,895.0	0.0	0.0	0.0	790.9	0.0	7,486.9
2003	0.0	2,361.4	10.0	8.0	0.8	0.0	0.0	2.0	0.0	29.0	0.0	27.5	0.0	0.0	0.0	522.0	0.0	0.0	165.0	997.0	0.0	4,122.7
2004	0.0	3,610.0	43.3	20.0	49.1	0.0	0.0	0.0	1,911.0	0.0	35.5	17.5	0.0	0.0	0.0	1,187.0	0.0	0.0	0.0	1,614.7	0.0	8,488.1
2005	0.0	5,824.6	961.0	281.0	51.4	0.0	340.0	174.2	242.0	21.5	0.0	65.1	0.0	0.0	0.0	6,360.0	0.0	0.0	24.0	6,020.0	0.0	20,364.9
2006	0.0	4,188.1	454.3	607.5	73.1	0.0	0.0	159.0	6,894.0	0.0	0.0	93.0	0.0	0.0	0.0	9,586.0	0.0	0.0	258.5	7,650.7	0.0	29,964.2
2007	0.0	13,944.6	941.2	215.9	149.5	0.0	16.0	161.6	368.0	0.0	0.0	56.5	3.3	0.0	0.0	9,078.0	190.0	0.0	50.5	18,525.6	0.0	43,700.6
2008	121.0	26,001.0	129.7	1,113.0	488.8	0.0	0.0	1,254.5	105.0	6.0	0.0	32.0	66.3	0.0	0.0	1,198.0	0.0	0.0	192.3	10,955.5	0.0	41,663.1
2009	34.0	5,548.4	14.0	66.0	214.2	0.0	0.0	133.9	1,933.8	4.5	16.0	15.2	636.5	0.0	0.0	1,273.0	5.5	0.0	148.0	6,672.6	0.0	16,715.6
2010	72.4	9,185.4	176.0	7.9	117.3	0.0	0.0	132.6	426.0	0.0	2.4	57.8	3,672.6	0.0	0.0	64.0	0.0	0.0	173.5	9,803.4	0.0	23,891.3
2011	24.1	19,744.0	29.5	0.0	172.5	0.0	0.0	30.0	182.0	0.0	14.0	75.3	2,014.0	0.0	0.0	357.0	0.0	0.0	49.0	5,576.4	0.0	28,267.8
2012	142.6	18,014.8	102.1	42.5	48.4	0.0	0.0	11.8	369.0	37.2	0.0	4.0	284.6	0.0	0.0	1,837.0	0.0	0.0	143.1	1,529.8	0.0	22,566.8
2013	217.4	10,493.1	1,201.8	5.0	11.2	0.0	0.0	89.4	102.0	59.7	0.0	1.6	231.7	0.0	0.0	158.0	40.0	0.0	44.7	1,296.6	0.0	13,952.1
2014	246.9	11,704.5	1,532.5	401.0	7.7	0.0	0.0	60.5	0.0	48.0	0.0	17.7	1,589.0	0.0	0.0	1,730.5	27.0	0.0	43.1	1,691.3	0.0	19,099.6
2015	546.9	27,540.8	1,324.5	0.0	0.9	2.3	34.0	0.0	0.0	320.4	13.0	31.4	2,920.7	2.0	0.0	47.0	606.5	0.0	0.0	2,160.6	0.0	35,550.9
2016	111.1	18,802.5	1,392.0	0.0	0.0	3.4	0.0	12.5	59.0	23.5	0.0	38.9	11,548.5	85.6	0.0	80.0	77.0	0.0	0.0	3,448.7	16.3	35,698.9
2017	24.6	5,477.6	691.0	0.0	4.1	2.7	0.0	20.5	39.1	97.1	0.0	33.8	13,651.8	424.9	0.0	14.0	17.0	0.0	0.0	5,137.0	90.0	25,725.3
2018	1,413.7	11,080.1	2,647.4	14.0	0.0	0.0	700.0	2.4	28.1	0.0	0.0	0.8	19,954.0	4,393.9	0.0	49.0	0.0	0.0	0.0	17,695.2	0.0	57,978.6
2019	5,511.3	3,332.5	1,587.1	13.0	0.0	3.0	500.0	99.0	0.0	0.0	0.0	0.0	27,787.5	9,557.9	0.0	11.0	0.0	0.0	0.0	11,405.4	0.0	59,807.6
2020	11,313.9	50.0	846.6	4.0	0.0	0.0	0.0	80.2	100.0	0.0	0.0	0.0	37,481.6	10,309.6	199.0	0.0	11.0	0.0	0.0	6,911.9	0.0	67,307.7
2021	25,907.1	2,129.0	771.0	0.0	392.9	5.0	30.0	23.5	0.0	14.4	0.0	0.0	49,138.7	14,871.2	10.0	0.0	0.0	0.0	20.0	11,160.0	0.0	104,472.8
2022	17,508.0	192.0	20.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	6.6	0.0	14,992.8	9,643.5	0.0	0.0	0.0	0.0	0.0	14,214.3	150.0	56,727.2
2023	1,325.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	720.0	109.5	0.0	0.0	0.0	0.0	0.0	100.0	0.0	2,254.5
Total	64,520.1	290,501.5	19,801.4	3,145.3	1,871.1	16.3	1,620.0	3,043.4	13,275.0	669.3	110.8	589.4	186,693.6	49,398.0	209.0	36,781.1	986.5	0.0	1,836.7	145,803.4	256.3	821,128.2

Combined Cycle Project Analysis

Table 12-35 shows the status of all combined cycle projects by number of projects that entered PJM generation queues from January 1, 1997, through March 31, 2023, by zone. Of the 39 combined cycle projects classified as new generation or upgrade currently active, suspended or under construction in the PJM generation queue, nine projects (23.1 percent) are located in the APS Zone.

Table 12-35 Status of all combined cycle queue projects by zone (number of projects): January 1, 1997 through March 31, 2023

		Number of Projects																						
Project Status	Project Classification	ACEC	AEP	AMPT	APS	ATSI	BGE	COMED	DAY	DUKE	DUQ	DOM	DPL	EKPC	JCPLC	MEC	OVEC	PECO	PE	PEPCO	PPL	PSEG	REC	Total
In Service	New Generation	1	6	0	3	4	2	2	0	2	0	7	2	0	7	4	0	5	2	4	9	5	0	65
	Upgrade	3	13	0	9	5	0	5	0	0	0	16	5	0	6	4	0	13	3	4	10	14	0	110
Under Construction	New Generation	0	1	0	0	0	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	2
	Upgrade	0	3	0	1	0	0	0	0	0	0	0	0	0	0	1	0	0	0	0	1	1	0	7
Suspended	New Generation	0	2	0	1	1	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	5
	Upgrade	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Withdrawn	New Generation	23	20	0	45	13	8	16	1	1	2	18	16	3	26	25	0	44	41	35	42	55	2	436
	Upgrade	8	8	0	10	4	0	4	0	1	0	11	5	0	8	7	0	3	5	5	8	15	0	102
Active	New Generation	0	0	0	4	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	5
	Upgrade	0	1	0	3	1	0	2	0	0	0	4	1	0	0	0	0	1	3	2	1	1	0	20
Total Projects	New Generation	24	29	0	53	19	10	20	1	3	2	25	18	3	33	29	0	49	43	39	51	60	2	513
	Upgrade	11	25	0	23	10	0	11	0	1	0	31	11	0	14	12	0	17	11	11	20	31	0	239

Table 12-36 shows the status of all combined cycle projects by MW that entered PJM generation queues from January 1, 1997, through March 31, 2023, by zone. Of the 12,761.4 MW of combined cycle projects classified as new generation or upgrade currently active, suspended or under construction in the PJM generation queue, 4,700.0 MW (36.8 percent) are located in the APS Zone.

Table 12-36 Status of all combined cycle queue projects by zone (MW): January 1, 1997 through March 31, 2023

		Project MW																						
Project Status	Project Classification	ACEC	AEP	AMPT	APS	ATSI	BGE	COMED	DAY	DUKE	DUQ	DOM	DPL	EKPC	JCPLC	MEC	OVEC	PECO	PE	PEPCO	PPL	PSEG	REC	Total
In Service	New Generation	650.0	4,511.0	0.0	1,970.0	3,751.0	140.0	1,800.9	0.0	533.0	0.0	5,828.6	319.2	0.0	1,665.8	2,557.0	0.0	2,665.0	1,900.0	1,560.0	5,892.0	1,698.5	0.0	37,441.9
	Upgrade	229.0	475.0	0.0	939.7	344.0	0.0	633.6	0.0	0.0	0.0	978.0	102.0	0.0	110.0	113.9	0.0	1,075.5	112.3	228.6	1,375.0	845.9	0.0	7,562.5
Under Construction	New Generation	0.0	1,100.0	0.0	0.0	0.0	0.0	1,150.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2,250.0
	Upgrade	0.0	825.0	0.0	20.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	75.0	0.0	0.0	0.0	0.0	51.6	51.1	0.0	1,022.7
Suspended	New Generation	0.0	1,150.0	0.0	1,270.0	955.0	0.0	575.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	3,950.0
	Upgrade	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Withdrawn	New Generation	8,542.4	13,559.5	0.0	21,832.1	8,641.0	3,122.1	10,817.0	1,150.0	134.5	665.0	12,961.0	5,145.4	991.8	13,562.6	13,001.0	0.0	24,140.0	16,114.0	22,268.2	18,917.7	24,244.6	6.9	219,816.7
	Upgrade	157.0	746.0	0.0	1,284.0	636.0	0.0	1,735.0	0.0	36.0	0.0	780.4	959.0	0.0	413.0	1,742.0	0.0	240.0	1,040.6	229.1	703.0	2,217.9	0.0	12,919.0
Active	New Generation	0.0	0.0	0.0	3,231.0	940.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	4,171.0
	Upgrade	0.0	285.0	0.0	179.0	58.0	0.0	111.7	0.0	0.0	0.0	118.0	451.0	0.0	0.0	0.0	0.0	5.0	115.0	45.0	0.0	0.0	0.0	1,367.7
Total Projects	New Generation	9,192.4	20,320.5	0.0	28,303.1	14,287.0	3,262.1	14,342.9	1,150.0	667.5	665.0	18,789.6	5,464.6	991.8	15,228.4	15,558.0	0.0	26,805.0	18,014.0	23,828.2	24,809.7	25,943.1	6.9	267,629.6
	Upgrade	386.0	2,331.0	0.0	2,422.7	1,038.0	0.0	2,480.3	0.0	36.0	0.0	1,876.4	1,512.0	0.0	523.0	1,930.9	0.0	1,320.5	1,267.9	502.7	2,129.6	3,114.9	0.0	22,871.9

Of the 39 combined cycle units in the queue as of March 31, 2023, in the status of Active, Under Construction or Suspended, 19 units, representing 3,982.4 MW had a projected in service date prior to January 1, 2023 and 20 units, representing 8,779.0 MW had a projected in service date between January 1, 2023, and November 2, 2026.

Combustion Turbine – Natural Gas Project Analysis

Table 12-37 shows the status of all combustion turbine natural gas projects by number of projects that entered PJM generation queues from January 1, 1997, through March 31, 2023, by zone. Of the 39 combustion turbine natural gas projects classified as new generation or upgrade currently active, suspended or under construction in the PJM generation queue, eight projects (20.5 percent) are located in the COMED Zone.

Table 12-37 Status of all combustion turbine – natural gas generation queue projects by zone (number of projects): January 1, 1997 through March 31, 2023

		Number of Projects																						
Project Status	Project Classification	ACEC	AEP	AMPT	APS	ATSI	BGE	COMED	DAY	DUKE	DUQ	DOM	DPL	EKPC	JCPLC	MEC	OVEC	PECO	PE	PEPCO	PPL	PSEG	REC	Total
In Service	New Generation	5	0	0	6	0	3	0	0	0	2	3	6	0	2	1	0	2	4	2	4	9	0	49
	Upgrade	4	11	0	10	3	0	17	6	0	0	28	8	0	5	2	0	4	4	3	4	14	0	123
Under Construction	New Generation	0	0	0	0	0	0	1	0	0	0	0	0	0	0	0	0	0	1	0	0	0	0	2
	Upgrade	0	0	0	0	2	0	2	0	0	0	0	0	0	0	3	0	0	4	0	0	0	0	11
Suspended	New Generation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1	0	1
	Upgrade	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Withdrawn	New Generation	1	6	0	0	0	2	1	1	0	0	4	0	1	1	0	0	1	5	0	1	5	0	29
	Upgrade	2	1	0	1	1	0	3	2	0	2	3	0	0	0	1	0	0	1	2	0	0	0	19
Active	New Generation	1	1	0	0	0	0	0	0	0	0	2	0	0	0	0	0	0	1	0	0	0	0	5
	Upgrade	2	2	0	1	4	0	5	1	0	0	1	0	0	0	0	0	0	1	3	0	0	0	20
Total Projects	New Generation	7	7	0	6	0	5	2	1	0	2	9	6	1	3	1	0	3	11	2	5	15	0	86
	Upgrade	8	14	0	12	10	0	27	9	0	2	32	8	0	5	6	0	4	10	8	4	14	0	173

Table 12-38 shows the status of all combustion turbine natural gas projects by MW that entered PJM generation queues from January 1, 1997, through March 31, 2023, by zone. Of the 4,951.2 MW of combustion turbine natural gas projects classified as new generation or upgrade currently active, suspended or under construction in the PJM generation queue, 1,138.0 MW (23.0 percent) are located in the DOM Zone.

Table 12-38 Status of all combustion turbine – natural gas queue projects by zone (MW): January 1, 1997 through March 31, 2023

		Project MW																						
Project Status	Project Classification	ACEC	AEP	AMPT	APS	ATSI	BGE	COMED	DAY	DUKE	DUQ	DOM	DPL	EKPC	JCPLC	MEC	OVEC	PECO	PE	PEPCO	PPL	PSEG	REC	Total
In Service	New Generation	360.7	0.0	0.0	1,176.0	0.0	23.0	0.0	0.0	0.0	219.4	1,081.0	1,140.0	0.0	520.0	10.0	0.0	559.0	361.9	5.0	150.9	925.9	0.0	6,532.8
	Upgrade	43.7	278.1	0.0	269.7	100.0	0.0	478.0	83.5	0.0	0.0	925.7	86.0	0.0	20.0	36.1	0.0	42.0	28.0	32.0	252.3	215.0	0.0	2,890.1
Under Construction	New Generation	0.0	0.0	0.0	0.0	0.0	0.0	190.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	18.0	0.0	0.0	0.0	0.0	208.0
	Upgrade	0.0	0.0	0.0	0.0	5.0	0.0	220.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	11.5	0.0	0.0	12.5	0.0	0.0	0.0	0.0	249.0
Suspended	New Generation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	675.0	0.0	675.0
	Upgrade	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Withdrawn	New Generation	7.5	1,519.0	0.0	0.0	0.0	153.6	10.0	104.0	0.0	0.0	1,069.8	0.0	73.0	2.1	0.0	0.0	0.5	326.8	0.0	19.9	1,140.1	0.0	4,426.3
	Upgrade	165.5	6.0	0.0	4.0	25.0	0.0	373.0	104.0	0.0	18.5	57.0	0.0	0.0	0.0	0.0	0.0	0.0	235.0	13.0	0.0	0.0	0.0	1,001.0
Active	New Generation	230.0	700.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1,138.0	0.0	0.0	0.0	0.0	0.0	0.0	463.0	0.0	0.0	0.0	0.0	2,531.0
	Upgrade	0.0	91.0	0.0	30.0	458.7	0.0	554.2	20.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	92.0	42.3	0.0	0.0	0.0	1,288.2
Total Projects	New Generation	598.2	2,219.0	0.0	1,176.0	0.0	176.6	200.0	104.0	0.0	219.4	3,288.8	1,140.0	73.0	522.1	10.0	0.0	559.5	1,169.7	5.0	170.8	2,741.0	0.0	14,373.1
	Upgrade	209.2	375.1	0.0	303.7	588.7	0.0	1,625.2	207.5	0.0	18.5	982.7	86.0	0.0	20.0	47.6	0.0	42.0	367.5	87.3	252.3	215.0	0.0	5,428.3

Wind Project Analysis

Table 12-39 shows the status of all wind generation projects, by number of projects that entered PJM generation queues from January 1, 1997, through March 31, 2023, by zone. Of the 157 wind projects classified as new generation or upgrade currently active, suspended or under construction in the PJM generation queue, 62 projects (39.5 percent) are located in the COMED Zone.

Table 12-39 Status of all wind generation queue projects by zone (number of projects): January 1, 1997 through March 31, 2023

		Number of Projects																					
Project Status	Project Classification	ACEC	AEP	AMPT	APS	ATSI	BGE	COMED	DAY	DUKE	DUQ	DOM	DPL	EKPC	JCPLC	MEC	OVEC	PECO	PE	PEPCO	PPL	PSEG	REC	Total
In Service	New Generation	1	19	0	18	0	0	26	0	0	0	3	0	0	0	0	0	0	23	0	8	0	0	98
	Upgrade	0	0	0	3	0	0	7	0	0	0	0	0	0	0	0	0	0	5	0	0	0	0	15
Under Construction	New Generation	0	0	0	0	0	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1
	Upgrade	0	0	0	0	0	0	2	0	0	0	0	0	0	0	0	0	0	1	0	0	0	0	3
Suspended	New Generation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Upgrade	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Withdrawn	New Generation	19	118	0	46	10	0	110	15	0	0	21	13	1	7	0	0	0	63	0	50	1	0	474
	Upgrade	2	2	0	7	0	0	8	0	0	0	3	1	0	0	0	0	0	6	0	2	0	0	31
Active	New Generation	5	16	0	7	1	0	35	1	0	0	8	9	0	9	0	0	0	3	0	1	2	0	97
	Upgrade	1	11	0	2	0	0	24	0	0	0	0	4	0	8	0	0	0	6	0	0	0	0	56
Total Projects	New Generation	25	153	0	71	11	0	172	16	0	0	32	22	1	16	0	0	0	89	0	59	3	0	670
	Upgrade	3	13	0	12	0	0	41	0	0	0	3	5	0	8	0	0	0	18	0	2	0	0	105

Table 12-40 shows the status of all wind projects by MW that entered PJM generation queues from January 1, 1997, through March 31, 2023, by zone. Of the 46,098.7 MW of wind projects classified as new generation or upgrade currently active, suspended or under construction in the PJM generation queue, 12,909.2 MW (28.0 percent) are located in the JCPLC Zone.

Table 12-40 Status of all wind generation queue projects by zone (MW): January 1, 1997 through March 31, 2023

		Project MW																					
Project Status	Project Classification	ACEC	AEP	AMPT	APS	ATSI	BGE	COMED	DAY	DUKE	DUQ	DOM	DPL	EKPC	JCPLC	MEC	OVEC	PECO	PE	PEPCO	PPL	PSEG	REC	Total
In Service	New Generation	7.5	3,544.6	0.0	1,364.0	0.0	0.0	4,088.9	0.0	0.0	0.0	322.5	0.0	0.0	0.0	0.0	0.0	0.0	1,047.0	0.0	226.5	0.0	0.0	10,601.0
	Upgrade	0.0	0.0	0.0	5.0	0.0	0.0	213.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	20.5	0.0	0.0	0.0	0.0	238.7
Under Construction	New Generation	0.0	0.0	0.0	0.0	0.0	0.0	200.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	200.0
	Upgrade	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	87.6	0.0	0.0	0.0	0.0	87.6
Suspended	New Generation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Upgrade	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Withdrawn	New Generation	4,943.6	24,301.4	0.0	3,552.2	1,814.0	0.0	25,593.9	2,128.0	0.0	0.0	4,988.4	3,240.8	150.3	7,397.0	0.0	0.0	0.0	5,257.0	0.0	3,835.2	20.0	0.0	87,221.6
	Upgrade	5.0	370.0	0.0	119.4	0.0	0.0	755.7	0.0	0.0	0.0	114.0	30.0	0.0	0.0	0.0	0.0	0.0	243.4	0.0	6.0	0.0	0.0	1,643.4
Active	New Generation	3,141.6	2,968.3	0.0	821.5	297.7	0.0	8,920.7	100.0	0.0	0.0	5,307.5	6,414.2	0.0	10,579.2	0.0	0.0	0.0	236.9	0.0	174.8	2,610.0	0.0	41,572.3
	Upgrade	0.0	12.6	0.0	207.6	0.0	0.0	483.4	0.0	0.0	0.0	0.0	955.3	0.0	2,330.0	0.0	0.0	0.0	249.8	0.0	0.0	0.0	0.0	4,238.7
Total Projects	New Generation	8,092.7	30,814.3	0.0	5,737.7	2,111.7	0.0	38,803.5	2,228.0	0.0	0.0	10,618.4	9,655.0	150.3	17,976.2	0.0	0.0	0.0	6,540.8	0.0	4,236.5	2,630.0	0.0	139,594.9
	Upgrade	5.0	382.6	0.0	332.0	0.0	0.0	1,452.2	0.0	0.0	0.0	114.0	985.3	0.0	2,330.0	0.0	0.0	0.0	601.3	0.0	6.0	0.0	0.0	6,208.4

Solar Project Analysis

Table 12-41 shows the status of all solar generation projects by number of projects that entered PJM generation queues from January 1, 1997, through March 31, 2023, by zone. Of the 1,917 solar projects classified as new generation or upgrade currently active, suspended or under construction in the PJM generation queue, 410 projects (21.4 percent) are located in the AEP Zone.

Table 12-41 Status of all solar generation queue projects by zone (number of projects): January 1, 1997 through March 31, 2023

		Number of Projects																						
Project Status	Project Classification	ACEC	AEP	AMPT	APS	ATSI	BGE	COMED	DAY	DUKE	DUQ	DOM	DPL	EKPC	JCPLC	MEC	OVEC	PECO	PE	PEPCO	PPL	PSEG	REC	Total
In Service	New Generation	10	11	0	10	0	1	1	1	1	0	54	14	1	54	0	0	1	3	1	2	46	0	211
	Upgrade	2	3	0	3	0	0	0	0	2	0	11	10	0	11	0	0	0	1	0	3	0	0	46
Under Construction	New Generation	1	5	0	3	3	0	1	1	0	3	17	5	0	0	3	0	0	1	1	1	3	0	48
	Upgrade	0	2	0	0	1	0	1	0	0	1	4	0	0	0	0	0	0	0	0	0	4	0	13
Suspended	New Generation	0	5	0	13	4	0	2	2	0	0	12	0	1	0	4	0	0	3	0	3	0	0	49
	Upgrade	0	0	0	1	0	0	0	0	0	0	1	0	0	1	0	0	0	0	0	0	0	0	3
Withdrawn	New Generation	192	137	0	103	36	15	48	27	16	2	263	158	17	198	30	1	11	79	25	62	121	0	1,541
	Upgrade	4	6	0	4	5	0	6	1	0	0	25	3	0	9	3	0	0	10	3	0	3	0	82
Active	New Generation	22	284	1	131	83	5	79	32	10	3	315	56	62	32	36	2	10	164	9	77	4	0	1,417
	Upgrade	2	114	1	34	31	0	30	15	2	0	56	16	7	3	11	3	0	36	0	26	0	0	387
Total Projects	New Generation	225	442	1	260	126	21	131	63	27	8	661	233	81	284	73	3	22	250	36	145	174	0	3,266
	Upgrade	8	125	1	42	37	0	37	16	4	1	97	29	7	24	14	3	0	47	3	29	7	0	531

Table 12-42 shows the status of all solar projects by MW that entered PJM generation queues from January 1, 1997, through March 31, 2023, by zone. Of the 128,935.2 MW of solar projects classified as new generation or upgrade currently active, suspended or under construction in the PJM generation queue, 44,073.5 MW (24.2 percent) are located in the AEP Zone.

Table 12-42 Status of all solar generation queue projects by zone (MW): January 1, 1997 through March 31, 2023

		Project MW																						
Project Status	Project Classification	ACEC	AEP	AMPT	APS	ATSI	BGE	COMED	DAY	DUKE	DUQ	DOM	DPL	EKPC	JCPLC	MEC	OVEC	PECO	PE	PEPCO	PPL	PSEG	REC	Total
In Service	New Generation	65.0	567.2	0.0	140.5	0.0	1.1	9.0	2.5	125.0	0.0	3,013.2	201.3	50.0	417.7	0.0	0.0	3.3	53.5	2.5	15.0	241.9	0.0	4,908.6
	Upgrade	0.0	170.0	0.0	0.0	0.0	0.0	0.0	0.0	75.0	0.0	86.1	0.0	0.0	14.3	0.0	0.0	0.0	0.0	0.0	10.0	0.0	0.0	355.4
Under Construction	New Generation	2.6	442.8	0.0	93.8	423.0	0.0	50.0	400.0	0.0	45.9	1,234.2	229.6	0.0	0.0	60.0	0.0	0.0	100.0	27.5	20.0	17.5	0.0	3,146.9
	Upgrade	0.0	147.0	0.0	0.0	20.0	0.0	50.0	0.0	0.0	8.3	32.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	3.8	0.0	261.1
Suspended	New Generation	0.0	284.9	0.0	323.6	395.0	0.0	32.5	278.0	0.0	0.0	909.8	0.0	95.0	0.0	12.0	0.0	0.0	43.9	0.0	27.8	0.0	0.0	2,402.4
	Upgrade	0.0	0.0	0.0	15.9	0.0	0.0	0.0	0.0	0.0	0.0	20.0	0.0	0.0	11.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	46.9
Withdrawn	New Generation	2,120.2	9,460.4	0.0	2,925.2	1,923.7	121.6	3,506.2	2,324.6	689.4	33.0	16,207.2	2,688.2	1,010.9	1,623.6	1,027.0	78.0	114.2	2,650.6	440.0	1,090.1	570.3	0.0	50,604.1
	Upgrade	172.5	126.0	0.0	32.9	213.0	0.0	110.0	20.0	0.0	0.0	1,113.6	5.0	0.0	23.8	15.0	0.0	0.0	53.7	3.6	0.0	1.3	0.0	1,890.3
Active	New Generation	617.7	39,045.6	40.0	5,695.9	5,309.3	154.9	12,216.4	2,654.9	648.9	34.7	27,970.3	2,019.5	5,745.2	669.0	581.1	340.0	129.4	5,425.7	210.7	2,293.8	37.9	0.0	111,840.7
	Upgrade	48.0	4,153.2	166.0	554.4	730.7	0.0	1,755.0	225.5	30.0	0.0	2,029.6	74.0	253.8	16.4	193.0	90.0	0.0	595.5	0.0	322.1	0.0	0.0	11,237.1
Total Projects	New Generation	2,805.5	49,800.9	40.0	9,178.8	8,051.0	277.6	15,814.1	5,659.9	1,463.3	113.6	49,334.6	5,138.6	6,901.1	2,710.2	1,680.1	418.0	246.9	8,273.6	680.6	3,446.7	867.6	0.0	172,902.8
	Upgrade	220.5	4,596.2	166.0	603.1	963.7	0.0	1,915.0	245.5	105.0	8.3	3,281.3	78.9	253.8	65.5	208.0	90.0	0.0	649.2	3.6	332.1	5.1	0.0	13,790.8

Battery Project Analysis

Table 12-43 shows the status of all battery generation projects by number of projects that entered PJM generation queues from January 1, 1997, through March 31, 2023, by zone. Of the 691 battery projects currently active, suspended or under construction in the PJM generation queue, 235 projects (34.0 percent) are located in the DOM Zone.

Table 12-43 Status of all battery generation queue projects by zone (number of projects): January 1, 1997 through March 31, 2023

		Number of Projects																						
Project Status	Project Classification	ACEC	AEP	AMPT	APS	ATSI	BGE	COMED	DAY	DUKE	DUQ	DOM	DPL	EKPC	JCPLC	MEC	OVEC	PECO	PE	PEPCO	PPL	PSEG	REC	Total
In Service	New Generation	0	2	0	3	0	0	7	1	4	0	0	0	0	2	0	0	1	0	0	1	2	0	23
	Upgrade	0	1	0	0	0	0	0	1	1	0	0	0	0	2	0	0	0	2	0	0	0	0	7
Under Construction	New Generation	0	0	0	0	0	1	0	0	0	0	1	0	0	2	0	0	0	0	0	0	0	0	4
	Upgrade	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Suspended	New Generation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1	2	0	3
	Upgrade	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Withdrawn	New Generation	7	33	0	4	7	25	28	3	3	1	33	17	1	37	4	0	4	4	1	7	4	0	223
	Upgrade	4	8	0	8	2	0	5	2	1	0	10	2	0	7	2	0	3	7	0	3	0	0	64
Active	New Generation	17	74	0	20	14	10	43	1	3	5	151	16	5	21	6	0	0	10	6	7	12	0	421
	Upgrade	6	51	1	17	10	1	48	5	1	0	83	8	3	4	5	0	0	17	0	2	1	0	263
Total Projects	New Generation	24	109	0	27	21	36	78	5	10	6	185	33	6	62	10	0	5	14	7	16	20	0	674
	Upgrade	10	60	1	25	12	1	53	8	3	0	93	10	3	13	7	0	3	26	0	5	1	0	334

Table 12-44 shows the status of all battery projects by MW that entered PJM generation queues from January 1, 1997, through March 31, 2023, by zone. Of the 54,422.0 MW of battery generation currently active, suspended or under construction in the PJM generation queue, 15,878.2 MW (29.2 percent) are located in the DOM Zone.

Table 12-44 Status of all battery generation queue projects by zone (MW): January 1, 1997 through March 31, 2023

		Project MW																						
Project Status	Project Classification	ACEC	AEP	AMPT	APS	ATSI	BGE	COMED	DAY	DUKE	DUQ	DOM	DPL	EKPC	JCPLC	MEC	OVEC	PECO	PE	PEPCO	PPL	PSEG	REC	Total
In Service	New Generation	0.0	6.0	0.0	39.9	0.0	0.0	86.0	12.0	16.0	0.0	0.0	0.0	0.0	40.0	0.0	0.0	1.0	0.0	0.0	20.0	3.0	0.0	223.9
	Upgrade	0.0	4.0	0.0	0.0	0.0	0.0	0.0	8.0	4.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	28.4	0.0	0.0	0.0	0.0	44.4
Under Construction	New Generation	0.0	0.0	0.0	0.0	0.0	1.0	0.0	0.0	0.0	0.0	20.0	0.0	0.0	14.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	35.0
	Upgrade	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Suspended	New Generation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	20.0	7.0	0.0	27.0
	Upgrade	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Withdrawn	New Generation	161.0	1,419.0	0.0	187.0	206.1	260.6	1,680.0	319.9	75.5	20.0	1,973.4	350.0	20.3	854.1	214.7	0.0	4.3	360.0	20.0	299.8	9.5	0.0	8,435.2
	Upgrade	20.0	302.2	0.0	209.0	20.3	0.0	325.0	95.0	20.0	0.0	183.0	14.0	0.0	55.1	30.0	0.0	60.0	41.0	0.0	20.0	0.0	0.0	1,394.6
Active	New Generation	2,039.5	8,591.5	0.0	1,927.5	2,010.0	1,342.5	6,184.8	85.0	475.0	505.0	13,949.2	909.0	176.0	1,498.8	526.2	0.0	0.0	905.8	796.0	395.0	1,760.0	0.0	44,076.8
	Upgrade	0.0	2,634.4	0.0	1,553.3	408.0	115.0	2,351.3	255.0	52.2	0.0	1,909.0	155.0	0.0	24.0	429.0	0.0	0.0	362.0	0.0	20.0	15.0	0.0	10,283.2
Total Projects	New Generation	2,200.5	10,016.5	0.0	2,154.4	2,216.1	1,604.1	7,950.8	416.9	566.5	525.0	15,942.6	1,259.0	196.3	2,406.9	740.9	0.0	5.3	1,265.8	816.0	734.8	1,779.5	0.0	52,797.9
	Upgrade	20.0	2,940.6	0.0	1,762.3	428.3	115.0	2,676.3	358.0	76.2	0.0	2,092.0	169.0	0.0	79.1	459.0	0.0	60.0	431.4	0.0	40.0	15.0	0.0	11,722.2

Renewable Hybrid Project Analysis

Table 12-45 shows the status of all renewable hybrid generation projects (solar + storage, solar + wind and wind + storage) by number of projects that entered PJM generation queues from January 1, 1997, through March 31, 2023, by zone.[62] Of the 455 renewable hybrid projects currently active, suspended or under construction in the PJM generation queue, 114 projects (25.1 percent) are located in the AEP Zone.

Table 12-45 Status of all renewable hybrid generation queue projects by zone (number of projects): January 1, 1997 through March 31, 2023

		Number of Projects																						
Project Status	Project Classification	ACEC	AEP	AMPT	APS	ATSI	BGE	COMED	DAY	DUKE	DUQ	DOM	DPL	EKPC	JCPLC	MEC	OVEC	PECO	PE	PEPCO	PPL	PSEG	REC	Total
In Service	New Generation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1	0	1
	Upgrade	0	0	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1
Under Construction	New Generation	0	0	0	0	0	0	0	0	0	0	1	0	0	0	0	0	0	0	0	0	2	0	3
	Upgrade	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1
Suspended	New Generation	0	0	0	6	0	0	0	0	0	0	0	0	3	0	7	0	0	1	0	1	0	0	18
	Upgrade	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1	0	0	1
Withdrawn	New Generation	4	12	0	8	6	0	6	0	0	0	30	2	8	1	1	0	0	5	1	6	10	0	100
	Upgrade	0	0	0	0	0	0	0	0	0	0	1	0	0	0	1	0	0	0	0	0	0	0	2
Active	New Generation	5	105	0	29	11	0	21	12	2	3	74	4	31	6	16	1	1	22	3	37	1	0	384
	Upgrade	1	8	0	6	3	0	3	3	0	0	8	0	4	0	1	0	0	5	0	6	0	0	48
Total Projects	New Generation	9	117	0	43	17	0	27	12	2	3	105	6	42	7	24	1	1	28	4	44	14	0	506
	Upgrade	1	9	0	7	3	0	3	3	0	0	9	0	4	0	2	0	0	5	0	7	0	0	53

Table 12-46 shows the status of all renewable hybrid projects by MW that entered PJM generation queues from January 1, 1997, through March 31, 2023, by zone. Of the 39,927.4 MW of renewable hybrid generation currently active, suspended or under construction in the PJM generation queue, 15,627.8 MW (39.1 percent) are located in the AEP Zone.

Table 12-46 Status of all renewable hybrid generation queue projects by zone (MW): January 1, 1997 through March 31, 2023

		Project MW																						
Project Status	Project Classification	ACEC	AEP	AMPT	APS	ATSI	BGE	COMED	DAY	DUKE	DUQ	DOM	DPL	EKPC	JCPLC	MEC	OVEC	PECO	PE	PEPCO	PPL	PSEG	REC	Total
In Service	New Generation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.1	0.0	1.1
	Upgrade	0.0	0.0	0.0	16.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	16.3
Under Construction	New Generation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	17.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2.6	0.0	19.6
	Upgrade	0.0	3.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	3.2
Suspended	New Generation	0.0	0.0	0.0	12.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	175.0	0.0	18.9	0.0	0.0	3.0	0.0	90.0	0.0	0.0	299.4
	Upgrade	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	50.0	0.0	0.0	50.0
Withdrawn	New Generation	14.5	3,860.8	0.0	568.0	484.9	0.0	986.9	0.0	0.0	0.0	2,289.9	104.5	1,004.0	20.0	20.0	0.0	0.0	304.2	20.0	201.0	36.1	0.0	9,914.8
	Upgrade	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	3.7	0.0	0.0	0.0	0.0	0.0	0.0	0.0	3.7
Active	New Generation	161.0	14,959.6	0.0	3,084.7	681.5	0.0	3,178.5	610.8	50.0	107.5	8,051.1	270.0	2,874.1	215.0	263.3	178.5	5.0	1,368.4	1,452.0	489.0	20.0	0.0	38,020.0
	Upgrade	60.0	665.0	0.0	0.0	60.1	0.0	20.0	40.0	0.0	0.0	199.0	0.0	165.0	0.0	0.0	0.0	0.0	115.2	0.0	211.0	0.0	0.0	1,535.3
Total Projects	New Generation	175.5	18,820.4	0.0	3,665.3	1,166.4	0.0	4,165.4	610.8	50.0	107.5	10,358.0	374.5	4,053.1	235.0	302.2	178.5	5.0	1,675.7	1,472.0	780.0	59.7	0.0	48,254.8
	Upgrade	60.0	668.2	0.0	16.3	60.1	0.0	20.0	40.0	0.0	0.0	199.0	0.0	165.0	0.0	3.7	0.0	0.0	115.2	0.0	261.0	0.0	0.0	1,608.5

62 PJM does not currently have a definition of a hybrid resource.

Relationship Between Project Developer and Transmission Owner

A transmission owner (TO) is an "entity that owns, leases or otherwise has a possessory interest in facilities used for the transmission of electric energy in interstate commerce under the tariff."[63] Where the transmission owner is a vertically integrated company that also owns generation, there is a potential conflict of interest when the transmission owner evaluates the interconnection requirements of new generation which is a competitor to the generation or transmission of the parent company and when the transmission owner evaluates the interconnection requirements of new generation which is part of the same company as the transmission owner. There is also a potential conflict of interest when the transmission owner evaluates the interconnection requirements of a nonincumbent transmission developer which is a competitor of the transmission owner. The MMU recommends outsourcing interconnection studies to an independent party to avoid potential conflicts of interest.

Table 12-47 shows the relationship between the project developer and transmission owner for all project MW that have entered the PJM generation queue from January 1, 1997, through March 31, 2023, by transmission owner and unit type. A project where the developer is affiliated with the transmission owner is classified as related. A project where the developer is not affiliated with the transmission owner is classified as unrelated. For example, 36.0 MW of combined cycle generation projects that have entered the PJM generation queue in the DUKE Zone were projects developed by Duke Energy or subsidiaries of Duke Energy, the transmission owner for the DUKE Zone. These project MW are classified as related. There have been 667.5 MW of combined cycle projects that have entered the PJM generation queue in the DUKE Zone by developers not affiliated with Duke Energy. These project MW are classified as unrelated.

Of the 821,128.2 MW that have entered the queue during the time period of January 1, 1997, through March 31, 2023, 71,128.6 MW (8.7 percent) have been submitted by transmission owners building in their own service territory. PSEG is the transmission owner with the highest percentage of affiliates building in their own service territory. Of the 39,536.7 MW that entered the queue in the PSEG Zone during the time period of January 1, 1997, through March 31, 2023, 13,532.3 MW (34.2 percent) were submitted by PSEG or one of their affiliated companies.

63 See OATT § 1 (Transmission Owner).

Table 12-47 Relationship between project developer and transmission owner for all interconnection queue projects MW by unit type: March 31, 2023

				MW by Unit Type																						
Parent Company	Transmission Owner	Related to Developer	Number of Projects	Battery	CC	CT - Natural Gas	CT - Oil	CT - Other	Fuel Cell	Hydro - Pumped Storage	Hydro - Run of River	Nuclear	RICE - Natural Gas	RICE - Oil	RICE - Other	Solar	Solar + Storage	Solar + Wind	Steam - Coal	Steam - Natural Gas	Steam - Oil	Steam - Other	Wind	Wind + Storage	Total	Percent of Total
AEP	AEP	Related	52	116.0	678.0	0.0	0.0	0.0	0.0	34.0	2.4	214.0	0.0	0.0	0.0	299.7	180.0	0.0	3,918.0	90.0	0.0	0.0	0.0	0.0	5,532.1	3.5%
		Unrelated	1,175	12,841.1	21,973.5	2,594.1	7.5	506.5	0.0	0.0	453.6	0.0	12.0	0.0	75.4	54,097.4	19,308.6	0.0	10,399.0	0.0	0.0	452.0	31,196.9	0.0	153,917.5	96.5%
AES	DAY	Related	14	20.0	0.0	47.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	21.5	0.0	0.0	1,347.5	0.0	0.0	0.0	0.0	0.0	1,436.0	11.6%
		Unrelated	129	754.9	1,150.0	264.5	0.0	12.0	0.0	0.0	0.0	0.0	0.0	0.0	10.0	5,883.9	650.8	0.0	0.0	0.0	0.0	0.0	2,228.0	0.0	10,954.1	88.4%
AMP	AMPT	Related	0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
		Unrelated	3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	206.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	206.0	100.0%
DUQ	DUQ	Related	0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
		Unrelated	48	525.0	665.0	237.9	40.0	19.2	0.0	0.0	194.6	1,879.0	0.0	0.0	0.0	121.9	107.5	0.0	2,810.0	0.0	0.0	20.0	0.0	0.0	6,620.1	100.0%
DOM	DOM	Related	203	1,171.7	11,397.5	2,045.7	100.0	0.0	0.0	340.0	0.0	1,944.0	0.0	0.0	60.0	6,349.2	17.0	0.0	301.0	0.0	0.0	4.0	2,786.0	0.0	26,516.2	22.0%
		Unrelated	1,151	16,862.9	9,268.5	2,225.8	0.5	227.3	0.0	0.0	35.0	0.0	0.0	10.0	119.4	46,266.7	10,390.0	0.0	20.0	0.0	0.0	316.3	7,946.4	150.0	93,838.8	78.0%
DUKE	DUKE	Related	12	37.3	36.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	105.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	178.7	5.6%
		Unrelated	43	605.4	667.5	0.0	0.0	0.0	0.0	0.0	112.0	0.0	0.0	0.0	4.8	1,462.9	40.0	10.0	120.0	0.0	0.0	0.0	0.0	0.0	3,022.6	94.4%
EKPC	EKPC	Related	2	0.0	821.8	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	821.8	6.4%
		Unrelated	146	196.3	170.0	73.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	7,154.9	4,218.1	0.0	0.0	0.0	0.0	0.0	150.3	0.0	11,962.5	93.6%
Exelon	ACEC	Related	4	0.0	530.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	8.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	538.3	2.2%
		Unrelated	385	2,220.5	9,048.4	807.4	388.0	20.7	2.8	0.0	0.0	0.0	2.0	5.0	10.3	3,017.7	235.5	0.0	15.0	5.5	0.0	10.0	8,097.7	0.0	23,886.5	97.8%
	BGE	Related	15	22.5	250.0	10.0	0.0	0.0	0.0	0.0	0.0	117.2	0.0	0.0	8.5	20.0	0.0	0.0	10.0	101.0	0.0	0.0	0.0	0.0	539.2	5.9%
		Unrelated	77	1,696.6	3,012.1	166.6	18.0	133.0	0.0	0.0	0.4	3,280.0	1.3	0.0	0.0	257.6	0.0	0.0	0.0	2.5	0.0	25.0	0.0	0.0	8,593.1	94.1%
	COMED	Related	17	0.0	0.0	296.0	0.0	0.0	0.0	0.0	0.0	1,185.0	0.0	0.0	0.0	9.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1,490.0	1.6%
		Unrelated	639	10,627.1	16,823.2	1,529.2	42.0	65.2	5.0	0.0	22.7	0.0	35.0	0.0	67.7	17,720.1	3,986.4	199.0	1,926.0	91.0	0.0	90.0	40,255.7	0.0	93,485.3	98.4%
	DPL	Related	5	1.0	60.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	7.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	68.4	0.3%
		Unrelated	418	1,427.0	6,916.6	1,226.0	600.9	40.5	0.0	0.0	0.0	0.0	0.0	0.0	84.6	5,210.2	374.5	0.0	653.0	15.0	0.0	65.0	10,640.3	0.0	27,253.5	99.7%
	PECO	Related	33	40.0	7,515.0	5.0	83.0	0.0	0.0	0.0	265.0	437.8	0.0	0.0	0.0	0.0	0.0	0.0	7.0	0.0	0.0	0.0	0.0	0.0	8,352.8	28.0%
		Unrelated	98	25.3	20,610.5	596.5	8.5	15.0	0.0	0.0	0.0	0.0	0.0	17.0	3.7	246.9	5.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	21,528.4	72.0%
	PEPCO	Related	5	1.0	503.0	0.0	0.0	4.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	508.0	1.7%
		Unrelated	119	815.0	23,827.9	92.3	34.0	5.0	0.0	0.0	0.0	1,640.0	32.0	0.0	3.5	684.3	1,472.0	0.0	0.0	6.0	0.0	0.0	0.0	0.0	28,612.0	98.3%
First Energy	APS	Related	10	0.0	1,453.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	71.2	0.0	0.0	1,710.0	0.0	0.0	0.0	0.0	0.0	3,234.2	5.2%
		Unrelated	654	3,916.7	29,272.8	1,479.7	0.0	84.4	0.0	0.0	638.3	0.0	154.4	53.8	25.4	9,710.8	3,665.3	0.0	4,092.0	0.0	0.0	184.4	6,069.7	16.3	59,363.9	94.8%
	ATSI	Related	6	0.0	1,678.0	0.0	0.0	0.0	0.0	0.0	0.0	16.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1,694.0	5.4%
		Unrelated	280	2,644.4	13,647.0	588.7	10.5	166.4	0.0	0.0	0.0	0.0	59.7	6.6	6.9	9,014.7	1,226.5	0.0	0.0	16.5	0.0	0.0	2,111.7	0.0	29,499.6	94.6%
	JCPLC	Related	2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	20.0	0.0	0.0	0.0	0.0	12.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	32.0	0.1%
		Unrelated	479	2,486.0	15,751.4	542.1	0.0	4.8	0.6	30.0	1.6	0.0	0.6	0.0	12.8	2,763.7	235.0	0.0	0.0	0.0	0.0	30.0	20,306.2	0.0	42,164.8	99.9%
	MEC	Related	0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
		Unrelated	213	1,199.9	17,488.9	57.6	1,204.4	52.1	0.0	0.0	0.0	93.0	0.0	8.0	23.2	1,888.1	305.9	0.0	0.0	0.0	0.0	84.0	0.0	0.0	22,405.1	100.0%
	PE	Related	4	0.0	534.0	5.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1,860.0	0.0	0.0	0.0	0.0	0.0	2,399.0	5.4%
		Unrelated	604	1,697.2	18,747.9	1,532.2	0.0	218.0	3.0	16.0	46.3	0.0	341.8	8.0	14.8	8,922.7	1,790.9	0.0	561.0	590.0	0.0	525.0	7,142.1	0.0	42,156.7	94.6%
OVEC	OVEC	Related	0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
		Unrelated	7	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	508.0	178.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	686.5	100.0%
PPL	PPL	Related	24	0.0	2,261.0	0.0	0.0	0.0	0.0	0.0	109.0	1,650.0	0.0	0.0	0.0	124.8	0.0	0.0	111.0	0.0	0.0	0.0	0.0	0.0	4,255.8	8.9%
		Unrelated	438	774.8	24,678.3	423.1	8.0	234.5	0.0	1,200.0	142.6	438.0	19.9	2.4	44.7	3,654.1	951.0	0.0	6,896.6	0.0	0.0	31.0	4,242.5	90.0	43,831.5	91.1%
PSEG	PSEG	Related	107	0.0	11,086.1	1,818.1	0.0	0.0	0.0	0.0	0.0	381.0	0.0	0.0	0.0	175.4	3.7	0.0	24.0	44.0	0.0	0.0	0.0	0.0	13,532.3	34.2%
		Unrelated	278	1,794.5	17,971.9	1,137.9	600.0	62.5	4.9	0.0	1,000.0	0.0	10.6	0.0	13.7	697.3	56.1	0.0	0.0	25.0	0.0	0.0	2,630.0	0.0	26,004.4	65.8%
Con Ed	REC	Related	0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
		Unrelated	2	0.0	6.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	6.9	100.0%
Total		Related	515	1,409.5	38,803.4	4,226.8	183.0	4.0	0.0	374.0	396.4	5,945.0	0.0	0.0	68.5	7,203.8	200.7	0.0	9,288.5	235.0	0.0	4.0	2,786.0	0.0	71,128.6	8.7%
		Unrelated	7,386	63,110.7	251,698.1	15,574.6	2,962.3	1,867.1	16.3	1,246.0	2,647.0	7,330.0	669.3	110.8	520.9	179,489.8	49,197.3	209.0	27,492.6	751.5	0.0	1,832.7	143,017.4	256.3	749,999.7	91.3%

Combined Cycle Project Developer and Transmission Owner Relationships

Table 12-48 shows the relationship between the project developer and transmission owner for all combined cycle project MW that have entered the PJM generation queue from January 1, 1997, through March 31, 2023, by transmission owner and project status. Of the 48,277.1 combined cycle project MW that are in service or currently under construction, 8,624.6 MW (17.9 percent) have been developed by transmission owners building in their own service territory. EKPC is the transmission owner with the highest percentage of affiliates building combined cycle projects in their own service territory. Of the 991.8 MW that entered the queue in the EKPC Zone during the time period of January 1, 1997, through March 31, 2023, 821.8 MW (82.9 percent) have been submitted by EKPC or one of their affiliated companies.

Table 12-48 Relationship between project developer and transmission owner for all combined cycle project MW in the queue: March 31, 2023

			MW by Project Status						
Parent Company	Transmission Owner	Related to Developer	Active	In Service	Under Construction	Suspended	Withdrawn	Total	Percent of Total
AEP	AEP	Related	0.0	678.0	0.0	0.0	0.0	678.0	3.0%
		Unrelated	285.0	4,308.0	1,925.0	1,150.0	14,305.5	21,973.5	97.0%
AES	DAY	Related	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
		Unrelated	0.0	0.0	0.0	0.0	1,150.0	1,150.0	100.0%
AMP	AMPT	Related	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
		Unrelated	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
DUQ	DUQ	Related	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
		Unrelated	0.0	0.0	0.0	0.0	665.0	665.0	100.0%
DOM	DOM	Related	94.0	4,762.5	0.0	0.0	6,541.0	11,397.5	55.2%
		Unrelated	24.0	2,044.1	0.0	0.0	7,200.4	9,268.5	44.8%
DUKE	DUKE	Related	0.0	0.0	0.0	0.0	36.0	36.0	5.1%
		Unrelated	0.0	533.0	0.0	0.0	134.5	667.5	94.9%
EKPC	EKPC	Related	0.0	0.0	0.0	0.0	821.8	821.8	82.9%
		Unrelated	0.0	0.0	0.0	0.0	170.0	170.0	17.1%
Exelon	ACEC	Related	0.0	0.0	0.0	0.0	530.0	530.0	5.5%
		Unrelated	0.0	879.0	0.0	0.0	8,169.4	9,048.4	94.5%
	BGE	Related	0.0	130.0	0.0	0.0	120.0	250.0	7.7%
		Unrelated	0.0	10.0	0.0	0.0	3,002.1	3,012.1	92.3%
	COMED	Related	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
		Unrelated	111.7	2,434.5	1,150.0	575.0	12,552.0	16,823.2	100.0%
	DPL	Related	0.0	60.0	0.0	0.0	0.0	60.0	0.9%
		Unrelated	451.0	361.2	0.0	0.0	6,104.4	6,916.6	99.1%
	PECO	Related	0.0	0.0	0.0	0.0	7,515.0	7,515.0	26.7%
		Unrelated	5.0	3,740.5	0.0	0.0	16,865.0	20,610.5	73.3%
	PEPCO	Related	0.0	80.0	0.0	0.0	423.0	503.0	2.1%
		Unrelated	45.0	1,708.6	0.0	0.0	22,074.3	23,827.9	97.9%
First Energy	APS	Related	0.0	525.0	0.0	0.0	928.0	1,453.0	4.7%
		Unrelated	3,410.0	2,384.7	20.0	1,270.0	22,188.1	29,272.8	95.3%
	ATSI	Related	0.0	0.0	0.0	0.0	1,678.0	1,678.0	10.9%
		Unrelated	998.0	4,095.0	0.0	955.0	7,599.0	13,647.0	89.1%
	JCPLC	Related	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
		Unrelated	0.0	1,775.8	0.0	0.0	13,975.6	15,751.4	100.0%
	MEC	Related	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
		Unrelated	0.0	2,670.9	75.0	0.0	14,743.0	17,488.9	100.0%
	PE	Related	0.0	0.0	0.0	0.0	534.0	534.0	2.8%
		Unrelated	115.0	2,012.3	0.0	0.0	16,620.6	18,747.9	97.2%
OVEC	OVEC	Related	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
		Unrelated	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
PPL	PPL	Related	0.0	600.0	0.0	0.0	1,661.0	2,261.0	8.4%
		Unrelated	0.0	6,667.0	51.6	0.0	17,959.7	24,678.3	91.6%
PSEG	PSEG	Related	0.0	1,738.0	51.1	0.0	9,297.0	11,086.1	38.2%
		Unrelated	0.0	806.4	0.0	0.0	17,165.5	17,971.9	61.8%
Con Ed	REC	Related	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
		Unrelated	0.0	0.0	0.0	0.0	6.9	6.9	100.0%
Total		Related	94.0	8,573.5	51.1	0.0	30,084.8	38,803.4	13.4%
		Unrelated	5,444.7	36,430.9	3,221.6	3,950.0	202,650.8	251,698.1	86.6%

Combustion Turbine – Natural Gas Project Developer and Transmission Owner Relationships

Table 12-49 shows the relationship between the project developer and transmission owner for all CT – natural gas project MW that have entered the PJM generation queue from January 1, 1997, through March 31, 2023, by transmission owner and project status. Of the 9,879.9 CT – natural gas project MW that are in service or currently under construction, 1,803.0 (18.2 percent) have been developed by Transmission Owners building in their own service territory. PSEG is the transmission owner with the highest percentage of affiliates building CT – natural gas projects in their own service territory. Of the 2,956.0 MW that entered the queue in the PSEG Zone during the time period of January 1, 1997, through March 31, 2023, 1,818.1 MW (61.5 percent) have been submitted by PSEG or one of their affiliated companies.

Table 12-49 Relationship between project developer and transmission owner for all CT – natural gas project MW in the queue: March 31, 2023

			MW by Project Status						
Parent Company	Transmission Owner	Related to Developer	Active	In Service	Under Construction	Suspended	Withdrawn	Total	Percent of Total
AEP	AEP	Related	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
		Unrelated	791.0	278.1	0.0	0.0	1,525.0	2,594.1	100.0%
AES	DAY	Related	0.0	47.0	0.0	0.0	0.0	47.0	15.1%
		Unrelated	20.0	36.5	0.0	0.0	208.0	264.5	84.9%
AMP	AMPT	Related	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
		Unrelated	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
DUQ	DUQ	Related	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
		Unrelated	0.0	219.4	0.0	0.0	18.5	237.9	100.0%
DOM	DOM	Related	1,138.0	824.0	0.0	0.0	83.7	2,045.7	47.9%
		Unrelated	0.0	1,182.7	0.0	0.0	1,043.1	2,225.8	52.1%
DUKE	DUKE	Related	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
		Unrelated	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
EKPC	EKPC	Related	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
		Unrelated	0.0	0.0	0.0	0.0	73.0	73.0	100.0%
Exelon	ACEC	Related	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
		Unrelated	230.0	404.4	0.0	0.0	173.0	807.4	100.0%
	BGE	Related	0.0	10.0	0.0	0.0	0.0	10.0	5.7%
		Unrelated	0.0	13.0	0.0	0.0	153.6	166.6	94.3%
	COMED	Related	296.0	0.0	0.0	0.0	0.0	296.0	16.2%
		Unrelated	258.2	478.0	410.0	0.0	383.0	1,529.2	83.8%
	DPL	Related	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
		Unrelated	0.0	1,226.0	0.0	0.0	0.0	1,226.0	100.0%
	PECO	Related	0.0	5.0	0.0	0.0	0.0	5.0	0.8%
		Unrelated	0.0	596.0	0.0	0.0	0.5	596.5	99.2%
	PEPCO	Related	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
		Unrelated	42.3	37.0	0.0	0.0	13.0	92.3	100.0%
First Energy	APS	Related	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
		Unrelated	30.0	1,445.7	0.0	0.0	4.0	1,479.7	100.0%
	ATSI	Related	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
		Unrelated	458.7	100.0	5.0	0.0	25.0	588.7	100.0%
	JCPLC	Related	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
		Unrelated	0.0	540.0	0.0	0.0	2.1	542.1	100.0%
	MEC	Related	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
		Unrelated	0.0	46.1	11.5	0.0	0.0	57.6	100.0%
	PE	Related	0.0	5.0	0.0	0.0	0.0	5.0	0.3%
		Unrelated	555.0	384.9	30.5	0.0	561.8	1,532.2	99.7%
OVEC	OVEC	Related	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
		Unrelated	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
PPL	PPL	Related	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
		Unrelated	0.0	403.2	0.0	0.0	19.9	423.1	100.0%
PSEG	PSEG	Related	0.0	912.0	0.0	0.0	906.1	1,818.1	61.5%
		Unrelated	0.0	228.9	0.0	675.0	234.0	1,137.9	38.5%
Con Ed	REC	Related	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
		Unrelated	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
Total		Related	1,434.0	1,803.0	0.0	0.0	989.8	4,226.8	21.3%
		Unrelated	2,385.2	7,619.9	457.0	675.0	4,437.5	15,574.6	78.7%

Wind Project Developer and Transmission Owner Relationships

Table 12-50 shows the relationship between the project developer and transmission owner for all wind project MW that have entered the PJM generation queue from January 1, 1997, through March 31, 2023, by transmission owner and project status. Of the 11,127.3 wind project MW that are in service or currently under construction, 12.0 MW (0.1 percent) have been developed by transmission owners building in their own service territory. DOM is the transmission owner with the highest percentage of affiliates building wind projects in their own service territory. Of the 10,732.4 MW that entered the queue in the DOM Zone during the time period of January 1, 1997, through March 31, 2023, 2,786.0 MW (26.0 percent) have been submitted by DOM or one of their affiliated companies.

Table 12-50 Relationship between project developer and transmission owner for all wind project MW in the queue: March 31, 2023

			MW by Project Status						
Parent Company	Transmission Owner	Related to Developer	Active	In Service	Under Construction	Suspended	Withdrawn	Total	Percent of Total
AEP	AEP	Related	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
		Unrelated	2,981.0	3,544.6	0.0	0.0	24,671.4	31,196.9	100.0%
AES	DAY	Related	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
		Unrelated	100.0	0.0	0.0	0.0	2,128.0	2,228.0	100.0%
AMP	AMPT	Related	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
		Unrelated	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
DUQ	DUQ	Related	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
		Unrelated	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
DOM	DOM	Related	2,640.0	12.0	0.0	0.0	134.0	2,786.0	26.0%
		Unrelated	2,667.5	310.5	0.0	0.0	4,968.4	7,946.4	74.0%
DUKE	DUKE	Related	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
		Unrelated	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
EKPC	EKPC	Related	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
		Unrelated	0.0	0.0	0.0	0.0	150.3	150.3	100.0%
Exelon	ACEC	Related	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
		Unrelated	3,141.6	7.5	0.0	0.0	4,948.6	8,097.7	100.0%
	BGE	Related	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
		Unrelated	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
	COMED	Related	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
		Unrelated	9,404.1	4,302.1	200.0	0.0	26,349.5	40,255.7	100.0%
	DPL	Related	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
		Unrelated	7,369.5	0.0	0.0	0.0	3,270.8	10,640.3	100.0%
	PECO	Related	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
		Unrelated	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
	PEPCO	Related	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
		Unrelated	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
First Energy	APS	Related	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
		Unrelated	1,029.1	1,369.0	0.0	0.0	3,671.6	6,069.7	100.0%
	ATSI	Related	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
		Unrelated	297.7	0.0	0.0	0.0	1,814.0	2,111.7	100.0%
	JCPLC	Related	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
		Unrelated	12,909.2	0.0	0.0	0.0	7,397.0	20,306.2	100.0%
	MEC	Related	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
		Unrelated	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
	PE	Related	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
		Unrelated	486.7	1,067.5	87.6	0.0	5,500.3	7,142.1	100.0%
OVEC	OVEC	Related	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
		Unrelated	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
PPL	PPL	Related	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
		Unrelated	174.8	226.5	0.0	0.0	3,841.2	4,242.5	100.0%
PSEG	PSEG	Related	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
		Unrelated	2,610.0	0.0	0.0	0.0	20.0	2,630.0	100.0%
Con Ed	REC	Related	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
		Unrelated	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
Total		Related	2,640.0	12.0	0.0	0.0	134.0	2,786.0	1.9%
		Unrelated	43,171.1	10,827.7	287.6	0.0	88,731.0	143,017.4	98.1%

Solar Project Developer and Transmission Owner Relationships

Table 12-51 shows the relationship between the project developer and transmission owner for all solar project MW that have entered the PJM generation queue from January 1, 1997, through March 31, 2023, by transmission owner and project status. Of the 8,672.0 solar project MW that are in service or currently under construction, 1,675.7 MW (19.3 percent) have been developed by transmission owners building in their own service territory. PSEG is the transmission owner with the highest percentage of affiliates building solar projects in their own service territory. Of the 872.7 MW that entered the queue in the PSEG Zone during the time period of January 1, 1997, through March 31, 2023, 175.4 MW (20.1 percent) have been submitted by PSEG or one of their affiliated companies.

Table 12-51 Relationship between project developer and transmission owner for all solar project MW in the queue: March 31, 2023

			MW by Project Status						
Parent Company	Transmission Owner	Related to Developer	Active	In Service	Under Construction	Suspended	Withdrawn	Total	Percent of Total
AEP	AEP	Related	100.0	34.7	0.0	0.0	165.0	299.7	0.6%
		Unrelated	43,098.8	702.5	589.8	284.9	9,421.4	54,097.4	99.4%
AES	DAY	Related	0.0	0.0	0.0	0.0	43.0	43.0	0.7%
		Unrelated	2,880.4	2.5	400.0	278.0	2,323.1	5,883.9	99.3%
AMP	AMPT	Related	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
		Unrelated	206.0	0.0	0.0	0.0	0.0	206.0	100.0%
DUQ	DUQ	Related	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
		Unrelated	34.7	0.0	54.2	0.0	33.0	121.9	100.0%
DOM	DOM	Related	4,507.4	1,288.1	202.0	99.9	251.9	6,349.3	12.1%
		Unrelated	25,492.5	1,811.2	1,064.2	829.9	17,068.9	46,266.7	87.9%
DUKE	DUKE	Related	49.0	0.0	0.0	0.0	56.4	105.4	6.7%
		Unrelated	629.9	200.0	0.0	0.0	633.0	1,462.9	93.3%
EKPC	EKPC	Related	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
		Unrelated	5,999.0	50.0	0.0	95.0	1,010.9	7,154.9	100.0%
Exelon	ACEC	Related	0.0	0.0	0.0	0.0	8.3	8.3	0.3%
		Unrelated	665.7	65.0	2.6	0.0	2,284.4	3,017.7	99.7%
	BGE	Related	0.0	0.0	0.0	0.0	20.0	20.0	7.2%
		Unrelated	154.9	1.1	0.0	0.0	101.6	257.6	92.8%
	COMED	Related	0.0	9.0	0.0	0.0	0.0	9.0	0.1%
		Unrelated	13,971.4	0.0	100.0	32.5	3,616.2	17,720.1	99.9%
	DPL	Related	0.0	7.4	0.0	0.0	0.0	7.4	0.1%
		Unrelated	2,093.4	194.0	229.6	0.0	2,693.2	5,210.2	99.9%
	PECO	Related	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
		Unrelated	129.4	3.3	0.0	0.0	114.2	246.9	100.0%
	PEPCO	Related	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
		Unrelated	210.7	2.5	27.5	0.0	443.6	684.3	100.0%
First Energy	APS	Related	71.2	0.0	0.0	0.0	0.0	71.2	0.7%
		Unrelated	6,179.0	140.5	93.8	339.5	2,958.0	9,710.8	99.3%
	ATSI	Related	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
		Unrelated	6,040.0	0.0	443.0	395.0	2,136.7	9,014.7	100.0%
	JCPLC	Related	0.0	0.0	0.0	0.0	12.0	12.0	0.4%
		Unrelated	685.4	432.0	0.0	11.0	1,635.4	2,763.7	99.6%
	MEC	Related	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
		Unrelated	774.1	0.0	60.0	12.0	1,042.0	1,888.1	100.0%
	PE	Related	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
		Unrelated	6,021.1	53.5	100.0	43.9	2,704.2	8,922.7	100.0%
OVEC	OVEC	Related	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
		Unrelated	430.0	0.0	0.0	0.0	78.0	508.0	100.0%
PPL	PPL	Related	124.8	0.0	0.0	0.0	0.0	124.8	3.3%
		Unrelated	2,491.2	25.0	20.0	27.8	1,090.1	3,654.1	96.7%
PSEG	PSEG	Related	0.0	129.3	5.2	0.0	40.9	175.4	20.1%
		Unrelated	37.9	112.6	16.1	0.0	530.7	697.3	79.9%
Con Ed	REC	Related	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
		Unrelated	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
Total		Related	4,852.3	1,468.5	207.2	99.9	597.5	7,225.3	3.9%
		Unrelated	118,225.5	3,795.6	3,200.8	2,349.4	51,918.4	179,489.8	96.1%

Battery Project Developer and Transmission Owner Relationships

Table 12-52 shows the relationship between the project developer and transmission owner for all battery project MW that have entered the PJM generation queue from January 1, 1997, through March 31, 2023, by transmission owner and project status. Of the 303.3 battery project MW that are in service or currently under construction, 60.0 MW (19.8 percent) have been developed by transmission owners building in their own service territory. PECO is the transmission owner with the highest percentage of affiliates building battery projects in their own service territory. Of the 65.3 MW that entered the queue in the PECO Zone during the time period of January 1, 1997, through March 31, 2023, 40.0 MW (61.3 percent) have been submitted by PECO or one of their affiliated companies.

Table 12-52 Relationship between project developer and transmission owner for all battery project MW in the queue: March 31, 2023

			MW by Project Status						
Parent Company	Transmission Owner	Related to Developer	Active	In Service	Under Construction	Suspended	Withdrawn	Total	Percent of Total
AEP	AEP	Related	100.0	6.0	0.0	0.0	10.0	116.0	0.9%
		Unrelated	11,125.9	4.0	0.0	0.0	1,711.2	12,841.1	99.1%
AES	DAY	Related	0.0	20.0	0.0	0.0	0.0	20.0	2.6%
		Unrelated	340.0	0.0	0.0	0.0	414.9	754.9	97.4%
AMP	AMPT	Related	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
		Unrelated	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
DUQ	DUQ	Related	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
		Unrelated	505.0	0.0	0.0	0.0	20.0	525.0	100.0%
DOM	DOM	Related	1,151.7	0.0	20.0	0.0	0.0	1,171.7	6.5%
		Unrelated	14,706.5	0.0	0.0	0.0	2,156.4	16,862.9	93.5%
DUKE	DUKE	Related	0.0	14.0	0.0	0.0	23.3	37.3	5.8%
		Unrelated	527.2	6.0	0.0	0.0	72.2	605.4	94.2%
EKPC	EKPC	Related	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
		Unrelated	176.0	0.0	0.0	0.0	20.3	196.3	100.0%
Exelon	ACEC	Related	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
		Unrelated	2,039.5	0.0	0.0	0.0	181.0	2,220.5	100.0%
	BGE	Related	2.5	0.0	0.0	0.0	20.0	22.5	1.3%
		Unrelated	1,455.0	0.0	1.0	0.0	240.6	1,696.6	98.7%
	COMED	Related	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
		Unrelated	8,536.1	86.0	0.0	0.0	2,005.0	10,627.1	100.0%
	DPL	Related	1.0	0.0	0.0	0.0	0.0	1.0	0.1%
		Unrelated	1,063.0	0.0	0.0	0.0	364.0	1,427.0	99.9%
	PECO	Related	0.0	0.0	0.0	0.0	40.0	40.0	61.3%
		Unrelated	0.0	1.0	0.0	0.0	24.3	25.3	38.7%
	PEPCO	Related	1.0	0.0	0.0	0.0	0.0	1.0	0.1%
		Unrelated	795.0	0.0	0.0	0.0	20.0	815.0	99.9%
First Energy	APS	Related	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
		Unrelated	3,480.8	39.9	0.0	0.0	396.0	3,916.7	100.0%
	ATSI	Related	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
		Unrelated	2,418.0	0.0	0.0	0.0	226.4	2,644.4	100.0%
	JCPLC	Related	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
		Unrelated	1,522.8	40.0	14.0	0.0	909.2	2,486.0	100.0%
	MEC	Related	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
		Unrelated	955.2	0.0	0.0	0.0	244.7	1,199.9	100.0%
	PE	Related	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
		Unrelated	1,267.8	28.4	0.0	0.0	401.0	1,697.2	100.0%
OVEC	OVEC	Related	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
		Unrelated	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
PPL	PPL	Related	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
		Unrelated	415.0	20.0	0.0	20.0	319.8	774.8	100.0%
PSEG	PSEG	Related	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
		Unrelated	1,775.0	3.0	0.0	7.0	9.5	1,794.5	100.0%
Con Ed	REC	Related	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
		Unrelated	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
Total		Related	1,256.2	40.0	20.0	0.0	93.3	1,409.5	2.2%
		Unrelated	53,103.8	228.3	15.0	27.0	9,736.6	63,110.7	97.8%

Renewable Hybrid Project Developer and Transmission Owner Relationships

Table 12-53 shows the relationship between the project developer and transmission owner for all renewable hybrid project MW that have entered the PJM generation queue from January 1, 1997, through March 31, 2023, by transmission owner and project status. Of the 40.1 renewable hybrid project MW that are in service or currently under construction, 20.7 MW (51.5 percent) have been developed by transmission owners building in their own service territory. PSEG is the transmission owner with the highest percentage of affiliates building hybrid projects in their own service territory. Of the 59.7 MW that entered the queue in the PSEG Zone during the time period of January 1, 1997, through March 31, 2023, 3.7 MW (6.2 percent) have been submitted by PSEG or one of their affiliated companies.

Table 12-53 Relationship between project developer and transmission owner for all hybrid project MW in the queue: March 31, 2023

			MW by Project Status						
Parent Company	Transmission Owner	Related to Developer	Active	In Service	Under Construction	Suspended	Withdrawn	Total	Percent of Total
AEP	AEP	Related	180.0	0.0	0.0	0.0	0.0	180.0	0.9%
		Unrelated	15,444.6	0.0	3.2	0.0	3,860.8	19,308.6	99.1%
AES	DAY	Related	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
		Unrelated	650.8	0.0	0.0	0.0	0.0	650.8	100.0%
AMP	AMPT	Related	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
		Unrelated	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
DUQ	DUQ	Related	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
		Unrelated	107.5	0.0	0.0	0.0	0.0	107.5	100.0%
DOM	DOM	Related	0.0	0.0	17.0	0.0	0.0	17.0	0.2%
		Unrelated	8,250.1	0.0	0.0	0.0	2,289.9	10,540.0	99.8%
DUKE	DUKE	Related	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
		Unrelated	50.0	0.0	0.0	0.0	0.0	50.0	100.0%
EKPC	EKPC	Related	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
		Unrelated	3,039.1	0.0	0.0	175.0	1,004.0	4,218.1	100.0%
Exelon	ACEC	Related	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
		Unrelated	221.0	0.0	0.0	0.0	14.5	235.5	100.0%
	BGE	Related	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
		Unrelated	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
	COMED	Related	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
		Unrelated	3,198.5	0.0	0.0	0.0	986.9	4,185.4	100.0%
	DPL	Related	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
		Unrelated	270.0	0.0	0.0	0.0	104.5	374.5	100.0%
	PECO	Related	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
		Unrelated	5.0	0.0	0.0	0.0	0.0	5.0	100.0%
	PEPCO	Related	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
		Unrelated	1,452.0	0.0	0.0	0.0	20.0	1,472.0	100.0%
First Energy	APS	Related	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
		Unrelated	3,084.7	16.3	0.0	12.5	568.0	3,681.6	100.0%
	ATSI	Related	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
		Unrelated	741.6	0.0	0.0	0.0	484.9	1,226.5	100.0%
	JCPLC	Related	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
		Unrelated	215.0	0.0	0.0	0.0	20.0	235.0	100.0%
	MEC	Related	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
		Unrelated	263.3	0.0	0.0	18.9	23.7	305.9	100.0%
	PE	Related	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
		Unrelated	1,483.6	0.0	0.0	3.0	304.2	1,790.9	100.0%
OVEC	OVEC	Related	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
		Unrelated	178.5	0.0	0.0	0.0	0.0	178.5	100.0%
PPL	PPL	Related	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
		Unrelated	700.0	0.0	0.0	140.0	201.0	1,041.0	100.0%
PSEG	PSEG	Related	0.0	1.1	2.6	0.0	0.0	3.7	6.2%
		Unrelated	20.0	0.0	0.0	0.0	36.1	56.1	93.8%
Con Ed	REC	Related	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
		Unrelated	0.0	0.0	0.0	0.0	0.0	0.0	0.0%
Total		Related	180.0	1.1	19.6	0.0	0.0	200.7	0.4%
		Unrelated	39,375.3	16.3	3.2	349.4	9,918.5	49,662.6	99.6%

Network Transmission Project Costs

Any entity that requests interconnection of a new generating facility, including increases to the capacity of an existing generating unit, or that requests interconnection of a merchant transmission facility, must follow the process defined in the PJM tariff to obtain interconnection service.[64] PJM's process is designed to ensure that new generation is added in a reliable and systematic manner. As part of the interconnection planning process, a series of studies are performed to determine the feasibility, impact, and cost of interconnecting projects in the queue. Interconnection requests are for energy only resources and for capacity resources.

Interconnecting capacity resources must meet a higher standard than energy only resources. For interconnecting capacity resources, PJM performs deliverability studies that ensure that the energy from the proposed generator can be reliably provided to the PJM region. Deliverability studies identify network upgrades needed to ensure that the transmission system is capable of delivering the aggregate system generating capacity at peak load, including the new resource, with all firm transmission service modeled.[65] The interconnection service agreement identifies the transmission modifications needed to maintain the reliability of the transmission system as a result of a new service request. These identified modifications are known as network upgrades. In general, there are fewer network upgrades associated with energy only resources, as energy only resources are not required to be deliverable to the entire PJM footprint.[66] On March 31, 2023, there were 3,332 projects in generation request queues in the status of active, under construction or suspended, and 2,287 active network transmission upgrades. If a project is withdrawn from the queue, the network upgrades associated with that project are no longer required, unless it is required to support another queue project.

While not all projects in the queue require network upgrades, the number of planned network transmission upgrades is strongly correlated with the number of active projects in the queue. The number of planned network upgrades is also strongly correlated with the number of new generation projects requesting interconnection as a capacity resource. After the execution of an interconnection service agreement, queue projects become part of the RTEP study and the costs of any upgrade later necessary to preserve their Capacity Interconnection Rights are included as part of the overall transmission system costs paid by all transmission customers.

The system impact study is a detailed system analysis performed for new service requests that tests deliverability under peak load conditions and light load conditions. The system impact study identifies system constraints caused by the request and the local upgrades and network upgrades required to solve those constraints. The system impact study includes power flow analysis and short circuit analysis. The power flow analysis includes expected output level from the new resource under summer peak and light load system conditions.[67] PJM's recent improvements to the deliverability analyses reflect more accurate information about the expected performance of intermittent resources, by type of resource (solar fixed, solar tracking, onshore wind and offshore wind), by season (summer, winter and light load) and by region (PJM West, Mid-Atlantic and Dominion), under each of these system conditions. Those modifications are necessary to accurately reflect the expected output of intermittent resources under various seasons and system conditions as the penetration and role of intermittents in PJM increases.[68] For example, the expected output of onshore wind varies from its maximum facility output to zero, depending on weather conditions, and the expected output levels are used for each system load condition.[69]

Capacity resources receive Capacity Interconnection Rights (CIRs) based on the deliverable MW which result from a combination of upgrades paid for by each project and existing system capability. Intermittent resources also require CIRs. The level of CIRs required for intermittent resources has been significantly understated because the required CIRs have been based on the

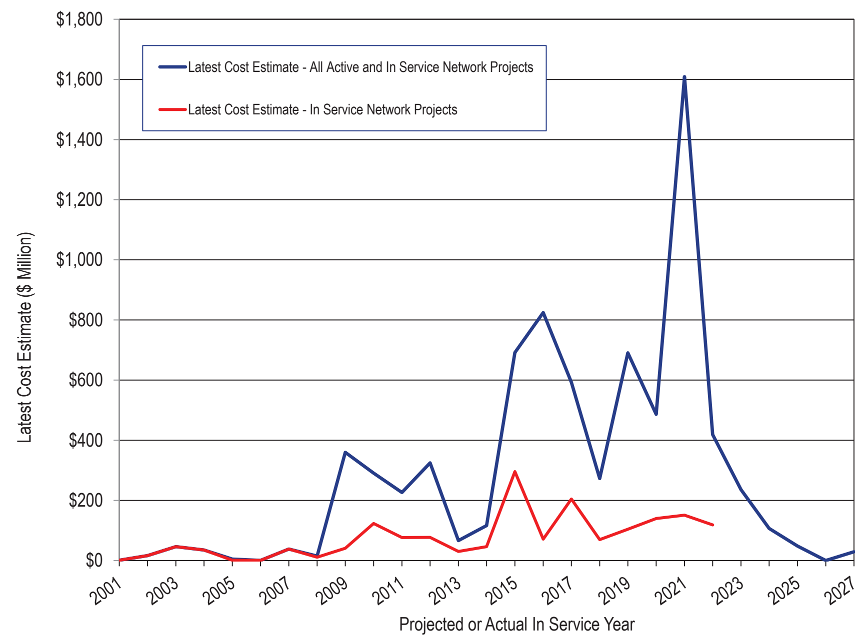
64 See OATT Parts IV & VI.
65 See "PJM Manual 14B: PJM Regional Transmission Planning Process," Rev. 51 (December 15, 2021).
66 See "PJM Manual 14B: Generation Interconnection Requests," Rev. 7 (October 20, 2021).
67 Winter peak load is included in the generation deliverability powerflow analysis during the RTEP baseline reliability analysis, but is not currently performed for new interconnection requests. The light load analysis ensures generation deliverability during light load conditions, which is defined as 50 percent of the annual peak demand.
68 See "PJM Manual 14B: PJM Region Transmission Planning Process," Rev. 51 (December 15, 2021).
69 See "Generation Deliverability Test Modifications: Light Load, Summer & Winter," presented at January 25, 2023 meeting of the Markets and Reliability Committee <https://www.pjm.com/-/media/committees-groups/committees/mrc/2023/20230125/consent-agenda-c---1-generator-deliverability-test-revisions---presentation.ashx>.

derated capacity value of intermittents rather than the maximum energy injections required to achieve the derated value.

After a lengthy stakeholder process, on April 7, 2023, FERC approved updates to PJM's ELCC method that cap the level of an intermittent generator's output used to calculate the generator's reliability contribution (ELCC derated MW) at the generator's CIR level.[70] Rules prior to the FERC order allowed generation at a level greater than the CIR value, and that was therefore not deliverable, to be inappropriately included in the ELCC calculations. For example, if a 100 MW solar resource has CIRs of 60 MW, generation in excess of 60 MW will not be included in the ELCC calculations under the updated rules. Prior to the update, the generation in excess of the CIR level was included, overstating the ELCC ratings and reliability contribution of ELCC resources. The overstatement of intermittent capacity has inefficiently suppressed capacity market clearing prices.[71] [72] In order to retain the prior ELCC values, existing intermittent generating units are required to increase their CIRs by going through an expedited queue process. The ELCC updates established a transitional period during which intermittent generators can be awarded temporary increases in their CIRs based on the availability of underutilized transmission system capability.[73] PJM expects a transitional period of four years, beginning with the 2025/2026 Base Residual Auction, to be sufficient time for intermittent resources to reenter the queue and be awarded additional CIRs. New intermittent generators will be required to pay for CIRs consistent with their calculated reliability contribution.

Figure 12-5 shows the latest network transmission project cost estimates by projected and actual in service year for network projects in the status of active or in service. The increase in estimated network upgrade costs for projects in the planning process in recent years is a result of the large number of requests in the new services queue and the existing backlog (Figure 12-5). However, as generation requests withdraw from the queue, the overall network costs decrease and the estimated network upgrade costs for in service projects are much lower. The projected in service dates for network projects are not updated regularly, and therefore, may not be an accurate predictor of when these projects are actually expected to go in service. PJM does not track final project costs, so the in service costs only reflect the last estimate provided by PJM before the project went in service. Given the significance of this information to market participants and regulators, the MMU recommends that estimated network costs for queue resources, in service dates for queue resources and final project interconnection costs be updated regularly and with accurate and verifiable data.

Figure 12-5 Cost estimates of network projects by projected and actual in service year: January 1, 2001 through December 31, 2027



70 183 FERC ¶61,009.
71 *See* "Analysis of the 2023/2024 RPM Base Residual Auction," <http://www.monitoringanalytics.com/reports/Reports/2022/IMM_Analysis_of_the_20232024_RPM_Base_Residual_Auction_20221028.pdf>. (October 28, 2022).
72 *See* "Analysis of the 2022/2023 RPM Base Residual Auction—Revised," <https://www.monitoringanalytics.com/reports/Reports/2023/IMM_Analysis_of_the_20222023_RPM_BRA_Revised_20230113.pdf> (January 13, 2023).
73 183 FERC ¶61,009 at 31.

Regional Transmission Expansion Plan (RTEP)[74]

The PJM RTEP process is designed to identify needed transmission system additions and improvements to continue to provide reliable service throughout the RTO. The objective of the RTEP process is to provide PJM with an optimal set of solutions necessary to solve reliability issues, operational performance issues and transmission constraints.

The RTEP process initially considered only factors such as load growth and the generation interconnection requests in its development of the 15 year plan. Currently, the RTEP process includes a broader range of inputs including the effects of public policy, market efficiency, interregional coordination and the effects of aging infrastructure.

RTEP Process

The PJM RTEP process is a 24 month planning process that identifies reliability issues for the next 15 year period. This 24 month planning process includes a process to build power flow models that represent the expected future system topology, studies to identify issues, stakeholder input and PJM Board of Managers approvals. The 24 month planning process is made up of overlapping 18 month planning cycles to identify and develop shorter lead time transmission upgrades and one 24 month planning cycle to provide sufficient time for the identification and development of longer lead time transmission upgrades that may be required to satisfy planning criteria.

Market Efficiency Process

PJM's Regional Transmission Expansion Plan (RTEP) process includes a market efficiency analysis. The stated purpose of the market efficiency analysis is: to determine which reliability based enhancements have economic benefit if accelerated; to identify new transmission enhancements that result in economic benefits; and to identify economic benefits associated with modification to existing RTEP reliability based enhancements that when modified would relieve one or more economic constraints. PJM identifies the economic benefit of proposed transmission projects based on production cost analyses.[75] PJM presents the RTEP market efficiency enhancements to the PJM Board, along with stakeholder input, for Board approval.

To be recommended to the PJM Board of Managers for approval, the relative benefits and costs of the economic based enhancement or expansion of the proposed project must reduce congestion on one or more constraints by at least one dollar, meet a ratio threshold of at least 1.25:1 and have an independent cost review, performed by PJM, if expected costs are over $50 million. PJM provides the review of a project with a projected cost of over $50 million using its own staff or outside consultants that are hired to assist in the review. PJM presents its findings to the TEAC where PJM's findings are reviewed by the stakeholders. While stakeholders can comment on the findings, PJM makes the final decision about what costs will be used for the purpose of calculating the cost/benefit ratio for the project. The cost/benefit ratio is the ratio of the present value of the total annual benefit for 15 years to the present value of the total annual cost for the first 15 years of the life of the enhancement or expansion.

The market efficiency process is comprised of a 12 month cycle and a 24 month cycle, both of which begin and end on the calendar year. The 12 month cycle is used for analysis of modifications and accelerations to approved RTEP projects only. The 24 month cycle is used for analysis of new economic transmission projects for years five through 15. This long-term proposal window takes place concurrently with the long-term proposal window for reliability projects.

PJM's first market efficiency analysis was performed in 2013, prior to Order 1000. The 2013 window was open from August 12, 2013, through September 26, 2013. This window accepted proposals to address historical congestion on 25 identified flowgates. PJM received 17 proposals from six entities. One project, submitted by an incumbent transmission owner, was approved by the PJM Board.

The first market efficiency cycle conducted under Order 1000 was performed during the 2014/2015 RTEP long term window. The 2014/2015 long term

74 The material in this section is based in part on the PJM Manual 14B: PJM Region Transmission Planning Process. See PJM. "PJM Manual 14B: PJM Region Transmission Planning Process," Rev. 51 (December 15, 2021).

75 See PJM. "*PJM Regional Transmission Expansion Plan: 2019*," (February 29, 2020) <https://www.pjm.com/-/media/library/reports-notices/2019-rtep/2019-rtep-book-1.ashx>.

window was open from November 1, 2014, through February 28, 2015. This window accepted proposals to address historical congestion on 12 identified flowgates. PJM received 93 proposals from 19 entities. Thirteen projects, all submitted by an incumbent transmission owner, were approved by the PJM Board.

The second market efficiency cycle was performed during the 2016/2017 RTEP long term window. The 2016/2017 long term window was open from November 1, 2016, through February 28, 2017. This window accepted proposals to address historical congestion on four identified flowgates. PJM received 96 proposals from 20 entities. Four projects, all submitted by an incumbent transmission owner, were approved by the PJM Board.

PJM also held an addendum 2016/2017 long term window. This 2016/2017 1A long term window was open from September 14, 2017, through September 28, 2017. This window accepted proposals to address historical congestion on one identified flowgate. PJM received three proposals from two entities. One project, submitted by an incumbent transmission owner, was approved by the PJM Board.

The fourth market efficiency cycle was performed for the 2018/2019 RTEP long term window. The 2018/2019 long term window was open from November 2, 2018, through March 15, 2019. This window accepted proposals to address historical congestion on one internal and three interregional flowgates. PJM received 33 proposals from 10 entities. One project, submitted by an incumbent transmission owner, was approved by the PJM Board to address the historical congestion on the internal flowgate, and one project, submitted by an incumbent transmission owner, was approved by the PJM Board to address the historical congestion on one of the interregional flowgates.[76]

The fifth market efficiency cycle was performed for the 2020/2021 RTEP long term window. The 2020/2021 RTEP long term window was open from November 11, 2020, through May 11, 2021. This window accepted proposals to address historical congestion on four internal flowgates. PJM received 24 proposals from seven entities. Four projects, all submitted by an incumbent transmission owner, were approved by the PJM Board.

The sixth market efficiency cycle is currently being performed for the 2022/2023 RTEP long term window. The 2022/2023 RTEP long term window opened in January 2023. PJM is currently developing the market efficiency base case.

The Cost/Benefit Evaluation

For an RTEP project to be recommended to the PJM Board of Managers for approval as a market efficiency project, the relative benefits and costs of the economic based enhancement or expansion must meet a cost/benefit ratio threshold of at least 1.25:1.

The total benefit of a project is calculated as the sum of the net present value of calculated energy market benefits and calculated reliability pricing model (RPM) benefits for a 15 year period, starting with the projected in service date of the project. PJM measures benefits as reductions in estimated load charges and production costs in the energy market and reductions in estimated load capacity payments and in system capacity costs in the capacity market, but does not weight increases and decreases in benefits equally. The method for calculating energy market benefits and reliability pricing model benefits depends on whether the project is regional or subregional. A regional project is any project rated at or above 230 kV. A subregional project is any project rated at less than 230 kv.

The energy market benefit analysis uses an energy market simulation tool that produces an hourly least-cost, security constrained market solution, including total operational costs, hourly LMPs, bus specific injections and bus specific withdrawals for each modeled year with and without the proposed RTEP project. Using the output from the model, PJM calculates changes in energy production costs and load energy payments.

The definition of the energy benefit analysis depends on whether the project is regional or subregional. For a regional project, the energy benefit for each modeled year is equal to 50 percent of the change in system wide total system

76 No proposals effectively resolved the congestion on two of the three identified interregional market efficiency flowgates.

energy production costs with and without the project plus 50 percent of the change in zonal load payments with and without the project, including only those zones where the project reduced the load payments. For subregional projects, the calculation of benefits for each modeled year ignores any impact on system wide energy production costs and is instead based only the change in zonal load energy payments with and without the project, but including only those zones where the project reduced the load energy payments.

In both the regional and subregional analysis, changes in zonal load energy payments are netted against changes in the estimated value of any Auction Revenue Rights (ARR) that sink in that zone for purposes of determining whether a zone benefits from a proposed RTEP project. Estimated ARR credits are calculated for each simulated year using the most recent planning year's actual ARR MW combined with FTR prices assumed to be equal to the market simulation's CLMP differences between ARR source and sink points. The value of the ARR rights with and without the RTEP project is evaluated based on changes in modeled CLMPs on the latest allocation of ARR rights. ARR MW allocations are not adjusted to reflect any potential changes in ARR allocations which may be allowed by the RTEP upgrade and the value of the ARRs are assumed to match the forecasted CLMP differences on the ARR paths.

The Reliability Pricing Model (RPM) Benefit analysis is conducted using the RPM solution software, with and without the proposed RTEP project, using a set of estimated capacity offers.

The definition of the benefit in the RPM benefit analysis depends on whether the project is regional or subregional. For a regional project, the RPM benefit for each modeled year is equal to 50 percent of the change in system wide total system capacity payments with and without the project plus 50 percent of the change in zonal capacity payments with and without the project, including only those zones where the project reduced the capacity payments. For subregional projects, the reliability pricing model benefits for each modeled year ignores any impact on system wide total capacity payments and is equal to the change in zonal capacity payments with and without the project, including only those zones where the project reduced the capacity payments.

The difference in the benefits calculation used in the regional and subregional cost/benefit threshold tests is related to how the direct costs of the transmission projects are allocated for approved regional and subregional projects. The costs of an approved regional project are allocated so that 50 percent of the total costs are allocated on a system wide load ratio share basis and the remaining 50 percent of the total costs are allocated to zones with projected energy market benefits and reliability pricing model benefits in proportion to those projected positive benefits. The costs of an approved subregional project are allocated so that the total costs of the project is allocated to zones with projected energy market benefits and reliability pricing model benefits in proportion to those projected positive benefits.

There are significant issues with PJM's cost/benefit analysis. The current rules governing cost/benefit analysis of competing transmission projects do not accurately measure the relative costs and benefits of transmission projects. The current rules do not account for the fact that the benefits of projects are uncertain and highly sensitive to the modeling assumptions used. The current rules explicitly ignore the increased zonal load costs that a project may create. The current rules do not account for the fact that the project costs are nonbinding estimates, are not subject to cost caps and may significantly exceed the estimated costs. These flaws have contributed to PJM approving market efficiency projects with forecasted benefits that do not exceed the forecasted costs.

The recent introduction of storage as transmission assets (SATA) raises a number of additional concerns about PJM's cost/benefit analysis. PJM's cost/cost analysis uses a 15 year forecast for purposes of evaluating benefits and costs of traditional transmission assets with an expected useful life of 50 years or more. Using the same 15 year horizon does not make sense for SATA resources with an expected useful life of 10 years or less, depending on use. Using a 15 year benefit horizon will exaggerate the forecasted benefit stream relative to the stream of benefits that could be produced over the expected useful life relative to traditional transmission assets. Further, the rules for how to account for the actual, and forecasted, revenues and charges for operating the SATA to provide transmission load relief have not been established.

Without clear rules on how to allocate operational revenues and costs it is impossible to develop forecasted benefits and/or costs of a SATA project.

The broader issue is that the market efficiency project approach explicitly allows transmission projects to compete against future generation projects, but without allowing the generation projects to compete. Projecting speculative transmission related benefits for 15 years based on the existing generation fleet and existing patterns of congestion eliminates the potential for new generation to respond to market signals. The market efficiency process allows assets built under the cost of service regulatory paradigm to displace generation assets built under the competitive market paradigm. The MMU recommends that the market efficiency process be eliminated.

The Transource Project

The Transource Project (Project 9A) is an example of a PJM approved market efficiency project that initially passed PJM's 1.25 cost/benefit threshold test despite having benefits, if accurately calculated, that were less than forecasted costs. This project also illustrates the risks of ignoring potential cost increases given that the costs included in the cost/benefit calculation are nonbinding estimates. The Transource Project was proposed in PJM's 2014/2015 RTEP long term window. PJM's 2014/2015 RTEP long term window was the first market efficiency cycle under Order 1000. The 2014/2015 long term window was open from November 1, 2014, through February 28, 2015. This window accepted proposals to address historical congestion on 12 identified flowgates. The AP South Interface was one of the 12 identified flow gates listed in the 2014/15 RTEP Long Term Proposal Window Problem Statement.

A total of 41 market efficiency projects were proposed to address congestion on the AP South Transmission Interface. Transource Energy LLC, together with Dominion High Voltage, submitted a proposal referenced by PJM as Project 9A (or IEC or the Transource project) to address AP South related congestion.

Project 9A was considered a subregional project based on its voltage level, meaning that changes in forecasted system costs were not considered for purposes of estimating the cost/benefit ratios. Instead, only reductions in zonal load costs were considered as a benefit of the project. Any increases in zonal load costs were ignored in the analysis.

The initial study had a benefit to cost ratio of 2.48, with a capital cost of $340.6 million. The sum of the positive (energy cost reductions) effects was $1,188.07 million. The sum of negative effects (energy cost increases) was $851.67 million. The net actual benefit of the project in the study was therefore $336.40 million, not the $1,188.07 used in the study. Using the total benefits (positive and negative) to compare to the net present value of costs, the benefit to cost ratio was 0.70, not 2.48. The project should have been rejected on those grounds.

Subsequent studies of the 9A project have reduced its benefit/cost ratio as a result of increased costs, decreased congestion on the AP South Interface since 2014 and a reduction in peak load forecasts since 2015.

PJM's 2019 study using simulations for years 2017, 2021, 2024 and 2027 had a cost benefit ratio of 2.10 with a capital cost of $383.63 million. The sum of the positive (energy cost reductions) effects was $855.19 million, a reduction of $322 million (28.0 percent) from the initial study. The sum of negative effects (energy cost increases) was $827.34 million, a reduction of $27.86 million (3.3 percent) from the results of the initial study. The net actual benefit of the project in the 2019 study was $27.85 million, not the $1,188.07 from the initial study. Using the total benefits (positive and negative) to compare to the net present value of costs in the 2019 analysis, the benefit to cost ratio was 0.07, not 2.10. The project should have been rejected on those grounds.

A portion of Project 9A in Pennsylvania was challenged in a proceeding at the Pennsylvania PUC. On May 20, 2021, the Pennsylvania PUC denied the Transource application to build in Pennsylvania based on failure to demonstrate need combined with negative economic and environmental effects.[77] Transource is appealing the decision at the state and federal level.[78]

77 See *Applications of Transource Pennsylvania, LLC for approval of the Siting and Construction of the 230 kV Transmission Line Associated with the Independence Energy Connection–East and West Projects in portions of York and Franklin Counties, Pennsylvania et al.*, Pennsylvania Public Utility Commission, Opinion and Order, Docket No. A-2017-2640195 et al. (May 20, 2021).

78 See *Transource Pennsylvania, LLC et al. v. Pennsylvania Public Utility Commission*, Docket No. 689 CD 2021 (Commonwealth of Pennsylvania Court); *Transource Pennsylvania LLC v. Gladys Brown Dutrieuille, et al.*, Docket No. 21-2567 (USDC M.D. Pa.).

On September 22, 2021, the PJM Board endorsed PJM's recommendation to suspend the Transource IEC (9A) Project, based on the rejection by the Pennsylvania PUC. Project 9A was removed from PJM's planning models pending future updates.[79] At the time of the suspension, $131.9 million in material, engineering, land rights and project support costs had been incurred by developers, but there was no increase in transmission capability associated with the project.[80]

While suspended, PJM is required by Schedule 6 of the Operating Agreement (OA) to "annually review the cost and benefits" of Board approved market efficiency projects that have not commenced construction or have not received state siting approval. Under Schedule 6, PJM's 2021 study showed a cost/benefit ratio of 1.00 with a capital cost of $453.71 million. The sum of the positive (energy cost reductions) effects was $452.4 million, a reduction of $735.7 million (-61.9 percent) from the initial study. The sum of negative effects (energy cost increases) was $452.4 million, a reduction of $399.3 million (46.9 percent) in the negative effects from the -$851.7 results of the initial study. The net benefit of the project in the 2021 study was -$159.8 million, not the $1,188.07 from the initial study. Using the total benefits (positive and negative) to compare to the net present value of costs in the 2019 analysis, the benefit to cost ratio was -0.35, not 2.10. The project should be rejected on these grounds rather than simply suspended.

PJM MISO Interregional Market Efficiency Process (IMEP)

PJM and MISO developed a process to facilitate the construction of interregional projects in response to the Commission's concerns about interregional coordination along the PJM-MISO seam. This process, called the Interregional Market Efficiency Process (IMEP), operates on a two year study schedule and is designed to address forward looking congestion. To qualify as an IMEP project, the project must be evaluated in a joint study process, qualify as an economic transmission enhancement in both PJM and MISO transmission expansion models and meet specific IMEP cost benefit criteria.[81] The allocation of costs to each RTO for IMEPs will be in proportion to the benefits received.

While the IMEP process is a joint effort, PJM and MISO perform their own analysis of benefits to their own system and each uses a different modeling approach and a different metric for determining the benefits of a proposed project. PJM makes use of the cost/benefit analysis used for its own internal market efficiency projects which will, by definition, overstate project benefits by ignoring areas where energy costs are increased. MISO, on the other hand, measures benefits as changes in projected system wide production cost caused by the project. The use of different approaches to measuring benefits is an issue when studying potential benefits of projects in a joint effort, and when using the defined benefits to allocate the costs of IMEP projects to each RTO. PJM's approach will over allocate the costs of IMEP projects to PJM members.

No interregional constraints were identified in either PJM or MISO's regional processes. Therefore, an IMEP study was not required during the 2020/2021 IMEP cycle.

PJM and MISO are currently performing an analysis to determine if an IMEP study will be required for the 2022/2023 IMEP cycle.

PJM MISO Targeted Market Efficiency Process (TMEP)

PJM and MISO developed the Targeted Market Efficiency Process (TMEP) to facilitate the resolution of historic congestion issues that could be addressed through small, quick implementation projects. The TMEP process operates on a 12 month study schedule. To qualify as a TMEP project, the project must have an estimated in service date by the third summer peak season from the year the project was approved, have an estimated cost of less than $20 million and must have estimated benefits, based on the projected congestion cost

79 Nick Dumitriu, Principal Engineer, PJM Market Simulation, Market Efficiency Update presented to the Transmission Expansion Advisory Committee (November 30, 2021) at 18 <https://www.pjm.com/-/media/committees-groups/committees/teac/2021/20211130/20211130-item-02-market-efficiency-update.ashx>.

80 Nick Dumitriu, Principal Engineer, PJM Market Simulation, Market Efficiency Update presented to the Transmission Expansion Advisory Committee (November 30, 2021) at 19 <https://www.pjm.com/-/media/committees-groups/committees/teac/2021/20211130/20211130-item-02-market-efficiency-update.ashx>.

81 See "Joint Operating Agreement Between the Midwest Independent Transmission System Operator, Inc. and PJM Interconnection, L.L.C.," (December 11, 2008) <http://www.pjm.com/directory/merged-tariffs/miso-joa.pdf>.

relief over a four year period, that exceed the expected installed capacity cost of the proposed project.[82] [83]

The benefit of a proposed TMEP project is calculated as the value of eliminating congestion on the affected constraint over a four year period. PJM and MISO calculate the estimated value of eliminating congestion by calculating the average congestion for the two prior years prior and multiplying by four.

The allocation of costs to each RTO for an approved TMEP project will be in proportion to the benefits received by that RTO.[84] The proportion of benefits is calculated using the average shadow price of the constraint times the dfax to affected downstream buses times MW of load at the buses, which is effectively the proportion of congestion paid by the RTO. Within an RTO, the RTO's share of the cost of the approved project is allocated to each transmission control area in proportion to the benefits received by each transmission control area.

PJM and MISO did not conduct a TMEP study in 2019. As a result of decreases in M2M congestion and the addition of transmission upgrades already in process that affect the top congested historical M2M flowgates, PJM and MISO did not conduct a TMEP study in 2020. PJM and MISO agreed to assess the impact of planned upgrades and congestion using an additional year of market data. As a result, PJM and MISO did not conduct a TMEP study in 2021. The 2022 TMEP study focused on 23 flowgates as potential TMEP projects. Of the 23 initial flowgates, 19 were eliminated due to their relationship with other existing reliability projects already included in PJM's RTEP or MISO's MTEP plans, or the identified congestion was caused by outages.[85] Two projects were eliminated after studies showed that congestion was not persistent in October 2022, and an additional project was eliminated in December 2022 after further studies showed congestion was not persistent, leaving one TMEP project that was approved for implementation by the PJM Board on February 15, 2023, and by the MISO Board on March 23, 2023.[86] [87]

The PJM and MISO TMEP process for measuring the projected benefits of a TMEP transmission projects is flawed. The current rules incorrectly count congestion as a cost to load without accounting for how the congestion dollars are or are not returned to the load through the ARRs and FTRs. The benefit of a TMEP transmission upgrade should be the expected difference in the total cost of energy before and after the upgrade to all affected load. This measurement would include the change in expected LMP of all affected load before and after the upgrade, times the MW of load, plus the change in congestion dollars returned to the affected load before and after the upgrade. Congestion revenue returned to load is not a cost to the load, it is a credit against the overpayment of load payments relative to generation credits caused by the transmission constraint. Ignoring the return of congestion from ARRs/FTRs overstates the potential benefits of eliminating congestion through the TMEP upgrades, and ignores the value of smaller upgrades that may not eliminate a constraint, but may reduce the average cost of energy for load.

Multi Driver Process

On September 12, 2014, PJM filed revisions to the tariff to include provisions allowing PJM to include multi driver projects in its regional transmission expansion plan.[88] When a transmission project addresses a combination of reliability, market efficiency and/or public policy objectives, PJM can develop a multi driver approach project by identifying a more efficient or cost effective solution. PJM may choose a solution using either the proportional multi driver method or the incremental multi driver method. The proportional method combines separate solutions that address reliability, economics and/or public policy into a single transmission enhancement or expansion that incorporates separate drivers into one Multi-Driver Project. The incremental method expands or enhances a proposed single-driver solution to include one or more additional component(s) to address a combination of reliability,

82 See "Joint Operating Agreement Between the Midwest Independent Transmission System Operator, Inc. and PJM Interconnection, L.L.C.," (December 11, 2008) <http://www.pjm.com/directory/merged-tariffs/miso-joa.pdf>.
83 On November 2, 2017, PJM submitted a compliance filing including additional revisions to the MISO-PJM JOA to include stakeholder feedback in the TMEP project selection process. See *PJM Interconnection, L.L.C,* Docket No. ER17-718-000, et al. (November 2, 2017).
84 See *PJM Interconnection, L.L.C,* Docket No. ER17-729-000 (December 30, 2016).
85 See "Interregional Planning Update," presented at the August 9, 2022 meeting of the Transmission Expansion Advisory Committee. <https://www.pjm.com/-/media/committees-groups/committees/teac/2022/20220809/item-01---interregional-planning-update.ashx>.
86 See "Interregional Planning Update," presented at the October 4, 2022 meeting of the Transmission Expansion Advisory Committee. <https://www.pjm.com/-/media/committees-groups/committees/teac/2022/20221004/item-01----interregional-planning-update.ashx>.
87 See "PJM-MISO IPSAC," presented at the December 15, 2022 meeting of the PJM-MISO Inter-regional Planning Stakeholder Advisory Committee <https://www.pjm.com/-/media/committees-groups/stakeholder-meetings/ipsac/2022/20221215/ipsac-presentation.ashx>.
88 See PJM. Docket No. ER14-2864 (September 12, 2014).

economic and/or public policy drivers.[89] On February 20, 2015, the Commission approved the tariff revisions with an effective date of November 12, 2014.[90]

On June 7, 2022, PJM opened its first multi driver proposal window. The window seeks to address reliability and market efficiency needs on three identified facilities. PJM accepted proposed solutions until August 8, 2022. PJM received 14 proposals from three entities. After conducting an independent cost review, a reliability analysis and a market efficiency analysis on the 14 proposals and a combination of the proposals, PJM proposed a combination of two proposals (Project 644 + 908) as its preferred solution. Two separate companies made the two proposals that were picked (644 and 908). The preferred solution (Project 644 + 908) has an estimated capital cost of $82.30 million ($85.50 million in present value of payments), with a PJM determined expected cost/benefit ratio of 1.99.[91] PJM shared its recommendation with MISO for their evaluation. MISO did not indicate any concern with the proposed solution. On February 7, 2023, the PJM Board approved the recommended solution.

The cost/benefit analysis used in the multi driver review is the same flawed cost/benefit analysis that PJM uses for evaluating Market Efficiency projects. PJM's assumed benefit of the combined project was calculated as the sum of the present value of positive (energy cost reductions) effects of $169.8 million. The sum of the present value of negative effects (energy cost increases), which was ignored in the PJM calculation of benefits, was $149.1 million. The total benefit of the proposed multi driver project is therefore only $20.7 million, not the $169.8 asserted by PJM. Using the total benefits (positive and negative) to compare to the net present value of costs in the PJM's analysis, the benefit to cost ratio is 0.24, not 1.99. All $149.1 million of the increases in energy costs (negative benefits) would be paid by load in the ComEd zone.

Supplemental Transmission Projects

Supplemental projects are asserted to be "transmission expansions or enhancements that are not required for compliance with PJM criteria and are not state public policy projects according to the PJM Operating Agreement. These projects are used as inputs to RTEP models, but are not required for reliability, economic efficiency or operational performance criteria, as determined by PJM."[92] Attachment M-3 of the PJM OATT defines the process that Transmission Owners (TO) must follow in adding Supplemental Projects in their local plan.

The M-3 Process requires TOs to present the criteria, assumptions and models that they will use to plan and identify Supplemental Projects on a yearly basis. The criteria identified for Supplemental Projects are very broad and include: equipment material condition, performance and risk, operational flexibility and efficiency, infrastructure resilience, customer service or other, as well as asset management.

While the identification of the criteria violations and solutions are reviewed, and stakeholders have the opportunity to comment, the solution that is submitted in the Local Plan is the Transmission Owner's decision. PJM conducts a do no harm analysis to ensure the Supplemental Projects do not negatively affect the reliability of the system. Supplemental Projects are ultimately included in PJM's Regional Transmission Expansion Plan and are allocated 100 percent to the zone in which the transmission facilities are located. Supplemental Projects may displace projects that would have otherwise been implemented through the RTEP process.

Supplemental projects are currently exempt from the Order No. 1000 competitive process.[93] Transmission owners have a clear incentive to increase investments in rate base given that transmission owners are paid for these projects on a cost of service basis.

Figure 12-6 shows the latest cost estimate of all baseline and supplemental projects by expected in service year. FERC Order No. 890 was issued on February 16, 2007, and implemented in PJM starting in 2008. Order No. 890 required Transmission Providers to participate in a coordinated, open and transparent planning process. Prior to the implementation of Order No.

89 See "PJM Manual 14B: PJM Region Transmission Planning Process," Rev. 51 (December 15, 2021).
90 150 FERC ¶ 61,117 (February 20, 2015).
91 See "2022 RTEP Multi-Driver Proposal Window No. 1," presented at the December 6, 2022 meeting of the Transmission Expansion Advisory Committee <https://www.pjm.com/-/media/committees-groups/committees/teac/2022/20221206/item-07---multi-driver-proposal-window-update.ashx>.
92 See PJM. Planning. "Transmission Construction Status," (Accessed on March 31, 2023) <http://www.pjm.com/planning/rtep-upgrades-status/construct-status.aspx>.
93 FERC accepted tariff provisions that exclude supplemental projects from competition in the RTEP. 162 FERC ¶ 61,129 (2018), *reh'g denied*, 164 FERC ¶ 61,217 (2018).

890, there were transmission projects planned by transmission owners and included in the PJM planning models, that were not included in the totals shown in Figure 12-6, Table 12-54 and Table 12-55 because PJM did not track or report such projects. There has been a significant increase in supplemental projects coincident with the implementation of Order No. 890 starting in 2008 and the competitive planning process introduced by FERC Order No. 1000 starting in 2011.

Figure 12-6 Cost estimate of baseline and supplemental projects by expected in service year: January 1, 1998 through March 31, 2023

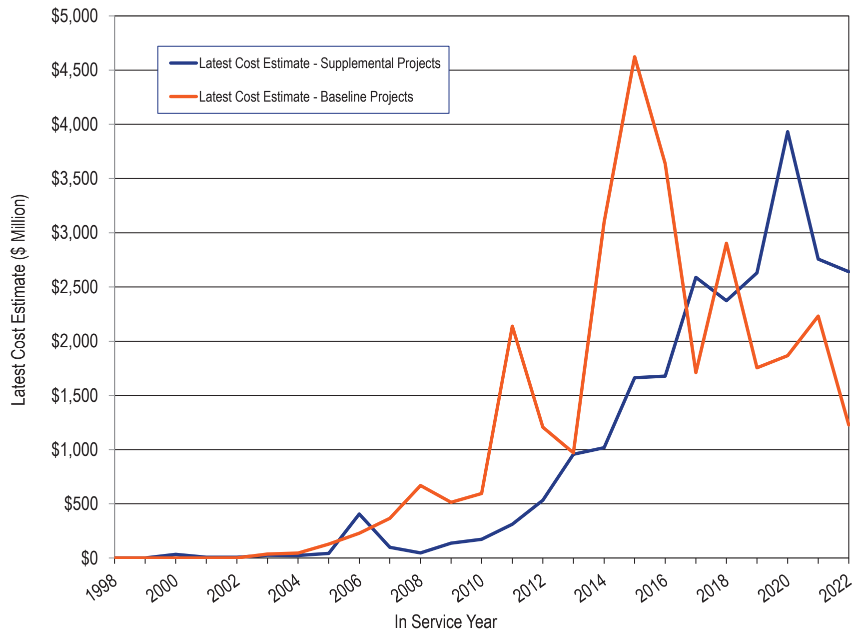


Table 12-54 shows the number of supplemental projects by expected in service year for each transmission zone. The average number of supplemental projects in each expected in service year increased by 975.0 percent, from 20 for years 1998 through 2007 (pre Order No. 890) to 215 for years 2008 through 2023 (post Order No. 890). As of March 31, 2023, there are 1,703 supplemental projects with expected in service dates between 2023 and 2027.

Table 12-54 Number of supplemental projects by expected in service year and zone: 1998 through 2040

Year	ACEC	AEP	AMPT	APS	ATSI	BGE	COMED	DAY	DUKE	DUQ	DOM	DPL	EKPC	JCPLC	MEC	NEET	OVEC	PECO	PE	PEPCO	PPL	PSEG	REC	Total
1998	0	0	0	0	0	0	0	0	0	0	0	3	0	0	0	0	0	0	0	0	0	0	0	3
1999	0	0	0	0	0	0	0	0	0	0	0	2	0	0	1	0	0	0	0	0	0	0	0	3
2000	0	0	0	0	0	0	0	0	0	0	0	11	0	0	0	0	0	0	0	0	0	0	0	11
2001	0	0	0	0	0	0	0	0	0	0	0	14	0	0	0	0	0	0	0	0	0	0	0	14
2002	0	0	0	0	0	0	0	0	0	0	0	10	0	0	0	0	0	0	0	0	0	0	0	10
2003	3	0	0	0	0	0	0	0	0	0	0	10	0	0	0	0	0	0	2	0	0	0	0	15
2004	5	0	0	10	0	0	9	0	0	0	0	12	0	2	0	0	0	0	0	0	0	2	0	40
2005	4	2	0	8	0	0	4	0	0	0	1	14	0	1	0	0	0	1	2	0	0	2	0	39
2006	4	2	0	5	0	0	6	0	0	0	0	9	0	1	0	0	0	0	1	0	2	1	0	31
2007	1	1	0	5	0	4	5	0	0	4	0	6	0	0	0	0	0	0	2	0	1	6	0	35
2008	3	0	0	15	0	1	6	0	0	1	7	3	0	0	1	0	0	0	0	0	3	1	0	41
2009	3	1	0	6	0	1	8	0	0	3	3	5	0	0	0	0	0	5	1	0	1	2	0	39
2010	0	6	0	7	0	3	4	0	0	6	3	0	0	1	2	0	0	2	0	0	3	5	0	42
2011	0	8	0	8	0	0	2	0	0	5	2	0	0	1	0	0	0	4	0	0	6	4	0	40
2012	0	5	0	6	4	1	2	0	7	3	16	1	0	2	0	0	0	1	0	0	5	11	0	64
2013	5	21	0	4	5	0	11	0	6	4	13	1	0	1	1	0	0	1	0	1	14	19	0	107
2014	2	31	0	2	8	2	14	0	5	6	18	3	3	2	0	0	0	1	2	0	9	16	0	124
2015	4	15	0	2	9	1	37	0	8	4	17	5	3	2	0	0	0	1	0	4	7	24	0	143
2016	6	17	0	4	17	0	26	0	6	2	13	4	2	0	1	0	0	3	2	3	11	30	0	147
2017	8	107	0	3	26	1	23	0	3	8	31	11	5	0	3	0	0	0	3	1	22	43	0	298
2018	10	143	0	3	13	1	20	0	14	3	22	6	4	0	0	0	0	2	0	1	20	26	0	288
2019	3	160	0	4	30	5	14	2	16	1	33	8	5	3	14	0	0	1	15	0	15	27	0	356
2020	5	132	0	4	33	6	12	5	13	1	30	2	6	10	17	0	0	3	35	1	17	22	0	354
2021	4	152	0	6	31	7	3	7	13	2	22	0	8	16	23	0	0	23	24	0	19	22	0	382
2022	1	154	0	8	40	5	10	7	8	1	28	2	6	14	49	0	0	6	25	4	16	18	0	402
2023	9	370	2	2	20	0	5	19	9	1	42	4	7	3	33	2	5	5	35	2	15	25	0	615
2024	7	266	0	3	12	2	4	12	3	1	29	5	3	11	29	0	0	0	29	4	15	10	0	445
2025	8	247	5	1	20	3	2	12	4	1	22	3	1	1	27	0	0	2	50	1	13	14	0	437
2026	5	45	0	0	8	7	1	5	3	0	17	2	2	4	5	0	0	0	2	0	5	17	0	128
2027	1	47	0	0	2	1	0	2	2	2	3	1	2	0	1	0	0	0	0	0	6	8	0	78
2028	0	16	0	0	0	0	0	0	2	1	2	1	2	0	0	0	0	1	5	0	5	0	0	35
2029	0	0	0	0	1	3	0	0	0	0	0	0	0	0	0	0	0	0	1	0	12	0	0	17
2030	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1	0	9	0	0	10
2031	0	0	0	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	9	0	0	10
2032	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	7	0	0	7
2033	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	7	0	0	7
2034	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	6	0	0	0	0	6
2035	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2036	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2037	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2038	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2039	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2040	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total	101	1,948	7	116	280	54	228	71	122	60	374	158	59	75	207	2	5	62	243	22	274	355	0	4,823

Table 12-55 shows the latest cost estimate of supplemental projects by expected in service year for each transmission zone. The average cost of supplemental projects in each expected in service year increased by 2,450.1 percent, from $64.6 million for years 1998 through 2007 (pre Order No. 890) to $1.8 billion for years 2008 through 2023 (post Order No. 890). As of March 31, 2023, the 1,703 supplemental projects with expected in service dates between 2023 and 2027, have a total cost estimate of $19.0 billion.

Table 12-55 Latest cost estimate by expected in service year and zone ($ millions): 1998 through 2040

Year	ACEC	AEP	AMPT	APS	ATSI	BGE	COMED	DAY	DUKE	DUQ	DOM	DPL	EKPC	JCPLC	MEC	NEET	OVEC	PECO	PE	PEPCO	PPL	PSEG	REC	Total
1998	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$1.67	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$1.67
1999	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.77	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.77
2000	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$32.94	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$32.94
2001	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$6.79	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$6.79
2002	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$7.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$7.00
2003	$7.42	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$8.77	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$9.60	$0.00	$0.00	$0.00	$0.00	$25.79
2004	$4.45	$0.00	$0.00	$10.00	$0.00	$0.00	$0.82	$0.00	$0.00	$0.00	$0.00	$7.33	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$22.60
2005	$4.06	$14.67	$0.00	$10.12	$0.00	$0.00	$2.57	$0.00	$0.00	$0.00	$0.02	$10.99	$0.00	$0.00	$0.00	$0.00	$0.00	$0.50	$0.00	$0.00	$0.00	$0.00	$0.00	$42.93
2006	$4.03	$309.70	$0.00	$0.94	$0.00	$0.00	$48.93	$0.00	$0.00	$0.00	$0.00	$11.62	$0.00	$6.00	$0.00	$0.00	$0.00	$0.00	$1.50	$0.00	$4.63	$18.80	$0.00	$406.15
2007	$0.56	$2.06	$0.00	$9.85	$0.00	$37.61	$4.65	$0.00	$0.00	$31.75	$0.00	$9.72	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.34	$2.28	$0.00	$98.82
2008	$2.36	$0.00	$0.00	$12.03	$0.00	$0.45	$7.61	$0.00	$0.00	$7.00	$14.01	$2.27	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$1.60	$0.00	$0.00	$47.33
2009	$0.77	$0.90	$0.00	$12.22	$0.00	$5.00	$21.11	$0.00	$0.00	$19.60	$2.12	$7.36	$0.00	$0.00	$0.00	$0.00	$0.00	$48.10	$2.73	$0.00	$0.16	$17.60	$0.00	$137.67
2010	$0.00	$34.36	$0.00	$12.13	$0.00	$18.90	$1.38	$0.00	$0.00	$34.45	$14.98	$0.00	$0.00	$0.03	$4.58	$0.00	$0.00	$31.80	$0.00	$0.00	$1.86	$17.72	$0.00	$172.19
2011	$0.00	$37.60	$0.00	$9.30	$0.00	$0.00	$1.00	$0.00	$0.00	$16.72	$85.67	$0.00	$0.00	$1.16	$0.00	$0.00	$0.00	$113.30	$0.00	$0.00	$11.87	$34.60	$0.00	$311.22
2012	$0.00	$46.00	$0.00	$5.12	$0.35	$2.20	$12.60	$0.00	$26.06	$11.60	$165.74	$0.99	$0.00	$6.61	$0.00	$0.00	$0.00	$12.60	$0.00	$0.00	$19.66	$223.01	$0.00	$532.54
2013	$3.15	$134.93	$0.00	$1.10	$33.68	$0.00	$59.25	$0.00	$9.93	$79.10	$25.03	$0.99	$0.00	$0.05	$4.10	$0.00	$0.00	$22.50	$0.00	$2.40	$76.70	$503.72	$0.00	$956.63
2014	$8.03	$387.00	$0.00	$5.97	$58.70	$21.20	$60.37	$0.00	$2.43	$14.90	$88.61	$5.96	$0.72	$5.60	$0.00	$0.00	$0.00	$13.30	$1.30	$0.00	$33.47	$309.71	$0.00	$1,017.27
2015	$3.73	$237.45	$0.00	$3.80	$21.90	$2.00	$376.00	$0.00	$14.12	$4.53	$113.53	$13.06	$1.22	$0.30	$0.00	$0.00	$0.00	$33.80	$0.00	$42.50	$50.17	$743.91	$0.00	$1,662.02
2016	$74.54	$84.13	$0.00	$18.40	$182.70	$0.00	$308.15	$0.00	$15.13	$26.95	$40.68	$26.60	$0.25	$0.00	$2.37	$0.00	$0.00	$86.40	$0.40	$7.80	$58.76	$744.18	$0.00	$1,677.44
2017	$66.28	$648.74	$0.00	$8.60	$164.45	$0.09	$145.97	$0.00	$64.31	$3.62	$104.25	$92.29	$2.21	$0.00	$14.70	$0.00	$0.00	$0.00	$8.30	$12.00	$264.34	$988.92	$0.00	$2,589.07
2018	$66.55	$816.23	$0.00	$14.60	$42.12	$4.08	$80.94	$0.00	$69.80	$3.13	$162.94	$68.94	$10.87	$0.00	$0.00	$0.00	$0.00	$47.60	$0.00	$156.00	$197.34	$631.25	$0.00	$2,372.39
2019	$64.30	$1,163.04	$0.00	$11.97	$190.40	$76.55	$90.19	$0.30	$90.69	$0.30	$90.14	$33.55	$23.67	$0.90	$62.30	$0.00	$0.00	$2.00	$75.80	$0.00	$298.00	$356.41	$0.00	$2,630.51
2020	$59.58	$920.44	$0.00	$0.30	$112.78	$62.58	$78.09	$13.66	$72.06	$6.40	$258.72	$39.50	$25.61	$2.60	$23.10	$0.00	$0.00	$2.40	$74.50	$102.70	$215.29	$1,861.58	$0.00	$3,931.89
2021	$86.54	$1,079.60	$0.00	$9.50	$184.21	$32.85	$125.70	$26.10	$117.39	$18.90	$98.40	$0.00	$25.67	$46.70	$85.89	$0.00	$0.00	$74.44	$63.48	$0.00	$197.67	$483.34	$0.00	$2,756.38
2022	$81.40	$628.36	$0.00	$13.98	$258.13	$203.30	$147.60	$36.05	$63.81	$45.00	$184.40	$9.38	$27.00	$30.50	$131.58	$0.00	$0.00	$73.68	$68.01	$2.79	$211.87	$423.43	$0.00	$2,640.27
2023	$185.45	$2,527.47	$27.20	$8.14	$165.61	$0.00	$34.30	$63.07	$120.42	$0.00	$305.64	$72.90	$43.26	$1.00	$256.96	$61.40	$4.40	$191.60	$85.70	$4.02	$176.28	$940.89	$0.00	$5,275.71
2024	$76.01	$1,919.53	$0.00	$6.14	$80.13	$118.00	$241.90	$92.20	$40.40	$3.25	$514.83	$87.80	$31.99	$95.90	$115.76	$0.00	$0.00	$0.00	$75.80	$809.47	$241.50	$321.01	$0.00	$4,871.62
2025	$213.99	$1,683.46	$80.20	$60.00	$697.10	$144.10	$104.00	$57.40	$38.40	$34.00	$622.08	$51.40	$3.80	$0.00	$154.80	$0.00	$0.00	$3.80	$103.80	$0.50	$428.90	$407.03	$0.00	$4,888.76
2026	$95.50	$644.12	$0.00	$0.00	$172.56	$687.25	$67.00	$30.10	$23.80	$0.00	$296.90	$58.78	$21.90	$24.00	$33.30	$0.00	$0.00	$0.00	$41.10	$0.00	$258.00	$404.50	$0.00	$2,858.81
2027	$17.13	$477.98	$0.00	$0.00	$16.40	$0.00	$0.00	$22.60	$30.62	$160.00	$119.50	$6.10	$28.01	$0.00	$10.00	$0.00	$0.00	$0.00	$0.00	$0.00	$83.80	$180.80	$0.00	$1,152.94
2028	$0.00	$365.44	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$26.50	$30.40	$1.00	$15.00	$30.78	$0.00	$0.00	$0.00	$0.00	$71.00	$140.10	$0.00	$112.26	$0.00	$0.00	$792.48
2029	$0.00	$0.00	$0.00	$0.00	$10.00	$276.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$136.39	$0.00	$0.00	$422.39
2030	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$200.00	$0.00	$181.88	$0.00	$0.00	$381.88
2031	$0.00	$0.00	$0.00	$0.00	$80.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$192.80	$0.00	$0.00	$272.80
2032	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$154.80	$0.00	$0.00	$154.80
2033	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$116.28	$0.00	$0.00	$116.28
2034	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$443.00	$0.00	$0.00	$0.00	$0.00	$443.00
2035	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
2036	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
2037	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
2038	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
2039	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
2040	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Total	$1,125.83	$14,163.21	$107.40	$244.21	$2,471.22	$1,692.16	$2,020.13	$341.48	$825.87	$551.60	$3,309.19	$690.47	$276.96	$221.35	$899.44	$61.40	$4.40	$828.82	$1,395.12	$1,140.18	$3,726.62	$9,614.69	$0.00	$45,711.75

The MMU recommends, to increase the role of competition, that the exemption of supplemental from the Order No. 1000 competitive process be terminated.

End of Life Transmission Projects

An end of life transmission project is a project submitted for the purpose of replacing existing infrastructure that is at, or is approaching, the end of its useful life. Under the current process, end of life transmission projects are not subject to the RTEP open window process and have become a form of supplemental project that is exempt from competition under the existing rules.[94]

The MMU recommends, to increase the role of competition, that the exemption of end of life projects from the Order No. 1000 competitive process be terminated and that end of life transmission projects be included in the RTEP process and should be subject to a transparent, robust and clearly defined mechanism to permit competition to build such projects.

Competitive Planning Process Exclusions

There are several project types that are currently exempt from the competitive planning process. These project types include:

- **Immediate Need Exclusion.** Due to the immediate need of the violation (3 years or less), the timing required for an RTEP proposal window is defined to be infeasible and such projects are excluded from competition. As a result, the local Transmission Owner is the Designated Entity.[95] On October 17, 2019, the Commission issued an Order Instituting Section 206 Proceedings to determine if RTOs have implemented the exemption in a manner consistent with the Commission's directives under Order 1000.[96] Some supplemental projects are in this category. In a decision issued August 19, 2022, the U.S. Court of Appeals for the D.C Circuit found that FERC reasonably approved MISO's Immediate Need Reliability Exception.[97] The Court rejected arguments challenging the MISO rule because (i) the definition of projects eligible for the exception was insufficiently limited and (ii) the rule allows for designating the incumbent developer before posting of the basis for the exception.[98] The decision was largely based on deference to FERC expertise.[99]
- **Below 200kV.** Due to the lower voltage level of the identified violation(s), the driver(s) for this project are excluded from competition. As a result, the local Transmission Owner is the Designated Entity.[100] Some supplemental projects are in this category.
- **Substation Equipment.** Due to identification of the limiting element(s) as substation equipment, such projects are excluded from competition. As a result, the local Transmission Owner is the Designated Entity.[101] Some supplemental projects are in this category.

While the PJM Operating Agreement defines who will be the Designated Entity for projects that are excluded from the competitive planning process, neither the PJM Operating Agreement nor the various commission orders on transmission competition prohibit PJM from permitting competition to provide financing for such projects. The MMU recommends that rules be implemented to permit competition to provide financing for transmission projects. This competition could reduce the cost of capital for transmission projects and significantly reduce total costs to customers. In addition, the criteria for and need for all exclusions from the competitive process should be reviewed. There does not appear to be any market reason to exclude transmission projects from competition for any of these exclusion categories.

Dominion Data Center Alley Immediate Need

An area in northern Virginia in the Dominion Transmission Zone, known as Data Center Alley, has experienced significant load growth due to increases in customer requests for data centers in the area. As a result, Dominion has presented 44 supplemental project requests to serve the increase in load through the summer of 2025. As part of the supplemental planning process, PJM performs a do no harm analysis. PJM has identified the need for additional baseline reinforcements to support the load growth. "Due to the pace and magnitude of load increase in the data center alley area, current operational

94 In recent decisions addressing competing proposals on end of life projects, the Commission accepted a transmission owner proposal excluding end of life projects from competition in the RTEP process, 172 FERC ¶ 61,136 (2020), *reh'g denied*, 173 FERC ¶ 61,225 (2020), and rejected a proposal from PJM stakeholders that would have included end of life projects in competition in the RTEP process, 173 FERC ¶ 61,242 (2020).
95 See OA Schedule 6 § 1.5.8(m).
96 169 FERC ¶ 61,054 (2019).
97 LSP Transmission Holdings II, LLC v. FERC, 45 F.4th 979.
98 *Id.* at 999.
99 *Id.*
100 See OA Schedule 6 § 1.5.8(n).
101 See OA Schedule 6 § 1.5.8(p).

and reliability constraints on the transmission system to serve load and consideration that a shortened competitive window will lead to delays of about 6 months, PJM has determined to designate Dominion construction responsibility to mitigate these immediate need violations."[102] [103] The proposed solution includes 500kV and 230kV lines extensions, the reconductoring of multiple 230kV lines and substation work. The initial cost estimate for the scope of work is $627.6 million.[104]

Comparative Cost Framework

The MMU recommended that rules be implemented to require that project cost caps on new transmission projects be part of the evaluation of competing projects. On May 24, 2018, the PJM Markets and Reliability Committee (MRC) approved a motion that required PJM, with input from the MMU, to develop a comparative cost framework to evaluate the quality and effectiveness of binding cost containment proposals versus proposals without cost containment provisions. On March 20, 2020, the Commission approved PJM's filing to amend the PJM Operating Agreement to incorporate this requirement.[105]

The 2020 RTEP Window 1 was the first open window that received cost capping proposals to be evaluated under the comparative cost framework. PJM has not provided the requested data to the MMU to allow for an analysis of their financial review process. Without this analysis, the MMU cannot verify that the analysis performed under the comparative cost framework was sufficient or adequately followed the process defined in the PJM manual.[106] The existing proposal templates do not provide enough information to adequately perform a financial analysis. The MMU recommends that PJM modify the project proposal templates to include data necessary to perform a detailed project lifetime financial analysis. The required data includes, but is not limited to: capital expenditure; capital structure; return on equity; cost of debt; tax assumptions; ongoing capital expenditures; ongoing maintenance; and expected life.

Storage As A Transmission Asset (SATA)

The PJM Planning Committee is currently considering whether storage devices should be included in the RTEP process as transmission assets.[107]

Transmission and generation have, and have always had, a symbiotic relationship in the provision of wholesale power. Transmission needs generation to function and generation needs transmission to function. Transmission can substitute for generation at the margin and generation can substitute for transmission at the margin. This relationship has always been a relatively unexamined area in the design of competitive wholesale power markets. For example, there is little if any explicit consideration of the impact of transmission planning on competitive generation investment in RTO/ISO market rules. Improvement is needed in these areas. Introducing confusion about what assets are classified as generation and what assets are classified as transmission frustrates potential reform and undermines the competitive markets.

On July 22, 2020, through the supplemental planning process, American Electric Power Service Corporation (AEP) filed, on behalf of Kentucky Power Company (Kentucky Power), a Petition for Declaratory Order seeking confirmation that its Middle Creek energy storage project is eligible for cost-of-service recovery through AEP's formula rates.[108] AEP's Middle Creek energy storage project was a proposed battery storage device that would discharge energy to serve retail load at the Middle Creek substation in the event of a transmission outage. On December 21, 2020, the Commission ruled that the Middle Creek energy storage project did not perform a transmission function, and was ineligible to recover its costs through formula rates.[109]

102 See "Dominion Northern Virginia Area Violations," presented at the July 12, 2022 meeting of the Transmission Expansion Advisory Committee. <https://www.pjm.com/-/media/committees-groups/committees/teac/2022/20220712/item-08---dominion-northern-virginia-area-violations---need-statement.ashx>.
103 See "Dominion Northern Virginia Area Immediate Need," presented at the July 12, 2022 meeting of the Transmission Expansion Advisory Committee. <https://www.pjm.com/-/media/committees-groups/committees/teac/2022/20220712/item-08---dominion-northern-virginia---immediate-need.ashx>.
104 See "Reliability Analysis Update Immediate Need," presented at the September 6, 2022 meeting of the Transmission Expansion Advisory Committee. <https://www.pjm.com/-/media/committees-groups/committees/teac/2022/20220906/item-09a---reliability-analysis-update---immediate-need.ashx>.
105 170 FERC ¶ 61,243 (2020).
106 See "PJM Manual 14F: Competitive Planning Process," Rev. 9 (April 27, 2022).
107 See PJM. "*Storage As A Transmission Asset: Problem / Opportunity Statement*," <https://pjm.com/-/media/committees-groups/committees/pc/2020/20200605-special/20200605-item-02a-storage-as-a-transmission-asset-problem-statement-clean.ashx>.
108 See *AEP*, Docket No. EL20-58 (July 22, 2020).
109 173 FERC ¶ 61,264 (2020).

Storage devices like batteries that are defined to be part of PJM markets should not be treated as transmission assets. The MMU recommends that storage resources not be includable as transmission assets for any reason.

Board Authorized Transmission Upgrades

The Transmission Expansion Advisory Committee (TEAC) regularly reviews internal and external proposals to improve transmission reliability throughout PJM. These proposals, which include reliability baseline, network, market efficiency and targeted market efficiency projects, as well as scope changes and project cancellations, but exclude supplemental and end of life projects, are periodically presented to the PJM Board of Managers for authorization.[110]

An RTEP project can be approved by the PJM Board if the project ensures compliance with NERC, regional and local transmission owner planning criteria or to address market efficiency congestion relief. These projects are considered Baseline Projects. PJM Board approved RTEP projects that are necessary to allow new generation to interconnect reliably are considered Network Projects.

In the first three months of 2023, the PJM Board approved a net change of $645.2 million in transmission upgrades. On February 15, 2023, the PJM Board authorized $645.2 million in transmission upgrades and additions. As of March 31, 2023, the PJM Board had approved $42.2 billion in transmission system enhancements since 1999.

Qualifying Transmission Upgrades (QTU)

A Qualifying Transmission Upgrade (QTU) is an upgrade to the transmission system that increases the Capacity Emergency Transfer Limit (CETL) into an LDA and can be offered into capacity auctions as capacity. Once a QTU is in service, the upgrade is eligible to continue to offer the approved incremental import capability into future RPM Auctions.

If a QTU that was cleared in a Base Residual Auction (BRA) or Incremental Auction (IA) is not completed by the start of the Delivery Year, the submitting party is required to provide replacement capacity. Once a QTU is in service, the upgrade is eligible to continue to offer the approved incremental import capability into future RPM Auctions. As of March 31, 2023, no QTUs have cleared a BRA or IA.

110 Supplemental Projects, including the end of life subset of supplemental projects, do not require PJM Board of Managers authorization.

Cost Allocation

In response to complaints against PJM RTEP Baseline Upgrade Filings in 2014 that included cost allocations for $1.5 billion in baseline transmission enhancements and expansions, on November 24, 2015, FERC issued an order directing investigation of "whether there is a definable category of reliability projects within PJM for which the solution-based DFAX cost allocation method may not be just and reasonable, such as projects addressing reliability violations that are not related to flow on the planned transmission facility, and whether an alternative just and reasonable *ex ante* cost allocation method could be established for any such category of projects."[111] FERC convened a technical conference on January 12, 2016, to address the complaints in multiple proceedings and to address these two core issues.[112]

The issues identified in the complaints and at the technical conference included: whether the solutions based allocation method is appropriate for upgrades not related to transmission overload issues; whether the solutions based allocation method correctly identifies all the beneficiaries of the upgrades; whether it is reasonable to allocate a level of costs to a merchant transmission project that could force bankruptcy; and whether the significant shifts in allocation that result from use of the 0.01 distribution factor cutoff are appropriate.

On February 20, 2020, the Commission issued an Order denying rehearing requests.[113] The Commission found that PJM's solution based dfax method for regional cost allocation, including the 0.01 distribution cutoff factor, is just and reasonable.

On appeal, the U.S. Court of Appeals for the D.C. Circuit found that FERC had failed to explain its distinction between the projects eligible to use the dfax method and those not eligible.[114] The Court objected that without adequate

111 153 FERC ¶ 61,245 at P 35 (2015).
112 See Docket Nos. EL15-18-000 (ConEd), EL15-67-000 (Linden), and EL15-95-000 (Artificial Island).
113 170 FERC ¶ 61,122 (2020).
114 See *Consolidated Edison v. FERC et al.*, 15-1183 et al, slip. op. (D.C. Cir. August 9, 2022).

explanation: "The Bergen project 'addresses a non-flow related reliability issue,' just like the non-flow-based stability issue in Artificial Island, but FERC had treated the two projects differently."[115] The Court also rejected the 0.01 distribution cutoff factor as "absurd."[116] The Court remanded issues concerning PJM's solution based dfax method to FERC, where the matter is now pending.

It is clear that the allocation issues are difficult. Nonetheless, the allocation methods affect the efficiency of the markets and the incentives for merchant transmission owners to compete to build new transmission. The MMU recommends a comprehensive review of the ways in which the solution based dfax is implemented. The goal for such a process would be to ensure that the most rational and efficient approach to implementing the solution based dfax method is used in PJM. Such an approach should allocate costs consistent with benefits and appropriately calibrate the incentives for investment in new transmission capability. No replacement approach should be approved until all potential alternatives are thoroughly reviewed.

As an example, the use of the arbitrary 0.01 distribution factor cutoff can result in large and inappropriate shifts in cost allocation. If the intent of the use of the 0.01 cutoff is to help eliminate small, arbitrary cost allocations to geographically distant areas, this could be achieved by adding a threshold for a minimum usage impact on the line. The MMU recommends changing the minimum distribution factor in the allocation from 0.01 to 0.00 and adding a threshold minimum impact on the load on the line based on a complete analysis of the intent of the allocation and the impacts of the allocation.

Transmission Line Ratings

Transmission line ratings, and more broadly transmission facility ratings, are the metric for the ability of transmission lines to transmit power from one point to another. Transmission line ratings have significant and frequently underappreciated impacts on competitive wholesale power markets like PJM. Line ratings directly impact energy and capacity prices, the frequency and level of congestion in the day-ahead and real-time energy market, day-ahead nodal price differences and the associated value of FTRs, locational price differences in the capacity market, the need to invest in additional transmission capacity, the need to invest in additional generation capacity, the location of new power plants, and the costs for the interconnection of new power plants. The impact of transmission facility ratings on markets is a function both of the line ratings directly and the use of those ratings by the RTO/ISO.

Congestion payments by load result when lower cost generation is not available to meet all the load in an area as a result of limits on the transmission system. When higher cost local generation is needed to meet part of the local load because of transmission limits, 100 percent of the local load pays the higher price while only the local generation receives the higher price. The difference between what the load pays and generators receive is congestion. Since 2008, congestion costs in PJM have ranged from $0.5 billion to $2.05 billion per year. Congestion costs were significantly higher during extreme winter weather conditions such as January 2014, when the congestion costs in PJM were $825.1 million for one month.[117]

LMP may, at times, be set by transmission penalty factors. When a transmission constraint is binding and there are no generation alternatives to resolve the constraint, system operators may allow the transmission limit to be violated. When this occurs, the shadow price of the constraint is set by transmission penalty factors. The shadow price directly affects the LMP. Transmission penalty factors are administratively determined and can be thought of as a form of locational scarcity pricing. Transmission penalty factors were fully implemented in PJM pricing effective February 1, 2019. The default transmission penalty factor is $2,000 per MWh.

Transmission line ratings can result in short term, significant increases in prices as a result of the application of transmission penalty factors. For example, violation of a transmission constraint, meaning that the flow exceeds the line limit, generally results in at least a $2,000 per MWh price. As the power flows approach their rated limits, PJM dispatchers often reduce the limits.[118] Violation of these reduced line ratings results in penalty factors

115 *Id.* at 9.
116 See *id.*

117 See the *2018 State of the Market Report for PJM*, Volume II, Section 11: Congestion and Marginal Losses.
118 See "Transmission Constraint Control Logic and Penalty Factors," presented at May 10, 2018 meeting of the Markets Implementation Committee Special Session Transmission Constraint Penalty Factors at p14. <https://www.pjm.com/-/media/committees-groups/committees/mic/20180510-special/20180510-item-03-transmission-constraint-penalty-factor-education.ashx>.

setting prices. In 2021, there were 170,067 transmission constraint intervals in the real-time market with a nonzero shadow price. For nearly eight percent of these transmission constraint intervals, the line limit was violated, meaning that the flow exceeded the facility limit. In 2021, the average shadow price of transmission constraints when the line limit was violated was nearly 8.8 times higher than when the transmission constraint was binding at its limit.[119]

Capacity market prices separate locally when transmission capability into Locational Deliverable Areas (LDA) is not adequate to meet the LDA capacity requirement with the lowest cost capacity. The available transmission capability into LDAs is defined as the Capacity Emergency Transfer Limit (CETL). Higher cost LDAs are the equivalent in the capacity market of congestion in the energy market. Load in the higher cost LDAs pay more for capacity than those in lower cost LDAs. For example, the clearing price for the BGE LDA in the 2021/2022 Base Residual Auction was $200.30 per MW-day. The clearing price for the EMAAC LDA was $165.73 per MW-day.[120]

Transmission line ratings for a given transmission facility vary by the duration of the power flow, by ambient temperatures, by wind speed and by other conditions. Transmission lines can operate with higher loads for shorter periods of time. This is significant when a contingency is expected to last for only a short period. The transmission line rating can mean the difference between substantial congestion costs and no congestion costs. The transmission line rating can mean the difference between a transmission penalty factor and no penalty factor.

In PJM, transmission owners use a range of ratings by duration.[121] PJM requires transmission owners to provide thermal ratings under normal operating conditions, long term emergency operating conditions, short term emergency operating conditions and the extreme load dump conditions. But there is no requirement that the ratings differ for these operating conditions. PJM typically uses normal line ratings for precontingency (base case) constraints and long term emergency line ratings (four hours) for contingency constraints. PJM requires transmission owners to provide temperature based line ratings separately for night and day times. The temperature ranges from 32 degree Fahrenheit or below to 95 degree Fahrenheit or above in nine degree increments. But there is no requirement that the ratings differ for these operating condition temperatures. In PJM, transmission owners are responsible for developing their own methods to compute line ratings subject to a range of NERC guidelines and requirements. PJM does not review or verify the accuracy of transmission owners' methods to compute line ratings. In PJM, transmission owners have substantial discretion in the approach to line ratings.[122]

Given the significant impact of transmission line ratings on all aspects of wholesale power markets, ensuring and improving the accuracy and transparency of line ratings is essential. Line ratings should incorporate ambient temperature conditions, wind speed and other relevant operating conditions. PJM real-time prices are calculated every five minutes for thousands of nodes. PJM prices are extremely sensitive to transmission line ratings. For consistency with the dynamic nature of wholesale power markets, line ratings should be updated in real time to reflect real time conditions and to help ensure that real-time prices are based on actual current line ratings. New technologies that permit dynamic line ratings (DLR) should be implemented.

Line ratings determine the actual value of transmission in market operations. Yet the methods for defining line ratings remain opaque and vary significantly across transmission owners. Under defining line ratings results in over building transmission. Over defining line ratings results in less reliability than planned for. Dynamic line ratings are essential to reflect the actual availability of transmission in real time as ambient conditions change. Ensuring that system operators have accurate information about line ratings, including a wide range of line ratings by duration of load, are essential to ensure that all market participants receive the maximum value from the investment in the transmission system.

119 See the *2020 State of the Market Report for PJM*, Volume II, Section 3: Energy Market.
120 See the "Analysis of the 2021/2022 RPM Base Residual Auction," <https://www.monitoringanalytics.com/reports/Reports/2018/IMM_Analysis_of_the_20212022_RPM_BRA_Revised_20180824.pdf> (August 24, 2018).
121 See "PJM Manual 3: Transmission Operations," Rev. 63 (Nov. 16, 2022) § 2.1.1, at p 27.
122 PJM presentation to the Planning Committee (PC) (May 3, 2018) "Transmission Owner Ratings Development and Reporting in PJM" ("There are no requirements for PJM to approve or verify a TO's ratings or do any kind of consistency check.") at 24.

Given the significant impact of transmission line ratings on all aspects of wholesale power markets, ensuring and improving the accuracy and transparency of line ratings is essential. Line ratings should incorporate ambient temperature conditions, wind speed and other relevant operating conditions. In PJM, real-time prices are calculated every five minutes for thousands of nodes. PJM prices are extremely sensitive to transmission line ratings.

The MMU recommends that all PJM transmission owners use the same methods to define line ratings and implement dynamic line ratings (DLR), subject to NERC standards and guidelines, subject to review by NERC, PJM and the MMU, and approval by FERC. The same facilities should have the same basic ratings under the same operating conditions regardless of the transmission owner. Transmission owner discretion should be minimized or eliminated. The line rating methods should be based on the basic engineering facts of the transmission system components and reflect the impact of actual operating conditions on the ratings of transmission facilities, including ambient temperatures and wind speed when relevant.[123] The line rating methods should be public and fully transparent.

The MMU recommends that PJM routinely review all transmission facility ratings and any changes to those ratings to ensure that the normal, emergency and load dump ratings used in modeling the transmission system are accurate and reflect standard ratings practice.[124] All line rating changes and the detailed reasons for those changes should be public and fully transparent.

The Commission recently adopted rules that enhance the ability of PJM and the MMU to understand and monitor line ratings on the PJM grid. Order No. 881, issued December 16, 2021, requires that: transmission providers implement ambient-adjusted ratings on transmission lines; RTOs/ISOs implement the systems and procedures necessary for hourly ratings updates; transmission providers use uniquely determined emergency ratings; transmission owners share transmission line ratings and transmission line rating methods with RTOs/ISOs and market monitors; transmission providers maintain a database of transmission line ratings and transmission line rating methods on OASIS or other password-protected website.[125] [126]

On rehearing, the Commission provided clarification of market monitors' ability to take action based on information received about transmission line ratings: "We expect that market monitors may use the transmission line rating information available to them in furtherance of their existing responsibilities, which are set forth in the Commission's regulations and the relevant tariffs of each RTO/ISO."[127]

Order No. 881 enhances transparency of information on line ratings and how they are determined. Requiring ambient and hourly adjustments constitutes substantive improvement. Continued reform consistent with the MMU's recommendations is needed in order to ensure consistent and accurate transmission line ratings in PJM.

Order No. 881 did not require the use of dynamic line ratings ("DLR") based on an insufficient record.[128] But on February 17, 2022, in Docket No. AD22-5, FERC issued a notice of inquiry addressing the DLR issues.[129]

Dynamic Line Ratings (DLR) and Grid Enhancing Technology (GETs)

For consistency with the dynamic nature of wholesale power markets, line ratings should be updated in real time to reflect real time conditions and to help ensure that real time prices are based on actual current line ratings. The relevant real-time conditions include ambient air temperature, wind speeds, solar heating, transmission line tension, and transmission line sag. The widespread adoption of dynamic line ratings should be pursued. The adoption of dynamic line ratings does not require the exorbitant incentives proposed by some. Dynamic line rating technology (DLR) and other Grid Enhancing Technology (GET) should be subject to competition and the costs of implementation should be capped at the costs that would result from

123 *See* "Transmission Owner Ratings Development and Reporting in PJM," presented at May 3, 2018 meeting of the Planning Committee.
124 *See* the *2018 State of the Market Report for PJM*, Volume II, Section 2: Recommendations.

125 *Managing Transmission Line Ratings*, Order No. 881, 177 FERC ¶ 61,179 at P 39 (2021) ("Order No. 881"), *order on reh'g*, Order No. 881-A, 179 FERC ¶ 61,125 (2022) ("Order No. 881-A").
126 *See* 18 CFR § 35.28(c)(5)(g)(13).
127 Order No. 881-A at P 91.
128 Order No. 881 at PP 25, 254
129 *Implementation of Dynamic Line Ratings*, Notice of Inquiry, 178 FERC ¶ 61,110 (2022).

the current cost of service method applied to transmission owners. The proposal that providers of GET should receive a share of forecast benefits is not consistent with competition, would pay rates of return many multiples of market rates of return and suffers from the same intractable problem of defining speculative benefits for long periods.

As a first step towards broader implementation of DLR by all transmission owners in PJM, PPL Electric Utilities, on its own initiative, implemented DLR for three 230 KV transmission lines in northeastern Pennsylvania on October 6, 2022, that have experienced congestion. (The two circuit Susquehanna-Harwood path and the Juniata-Cumberland line.) PPL provides streaming data from the DLR system to PJM operators.

Transmission Facility Outages

Scheduling Transmission Facility Outage Requests

A transmission facility is designated as reportable by PJM if a change in its status can affect a transmission constraint on any Monitored Transmission Facility or could impede free flowing ties within the PJM RTO and/or adjacent areas.[130] When a reportable transmission facility needs to be taken out of service, the transmission owner is required to submit an outage request as early as possible.[131] The specific timeline is shown in Table 12-57.[132]

Transmission outages have significant impacts on PJM markets, including impacts on FTR auctions, on congestion, and on expected market outcomes in the day-ahead and real-time markets. The efficient functioning of the markets depends on clear, enforceable rules governing transmission outages.

The outage data for the FTR market are for outages scheduled to occur in the 2021/2022 planning period and the first ten months of the 2022/2023 planning period, regardless of when they were initially submitted.[133] The outage data for the day-ahead market are for outages scheduled to occur from January 2015 through March 2023.

130 If a transmission facility is not modeled in the PJM EMS or the facility is not expected to significantly impact PJM system security or congestion management, it is not reportable. See PJM, "Manual 3: Transmission Operations," Rev. 63 (November 16, 2022).
131 See PJM, "Manual 3: Transmission Operations," Rev. 63 (November 16, 2022).
132 See PJM, "Manual 3: Transmission Operations," Rev. 63 (November 16, 2022).
133 The hotline tickets, EMS tripping tickets or test outage tickets were excluded. The analysis includes only the transmission outage tickets submitted by PJM companies which are currently active.

Transmission outages are categorized by duration: greater than 30 calendar days; less than or equal to 30 calendar days; greater than five calendar days; less than or equal to five calendar days.[134] Table 12-56 shows that 76.4 percent of requested outages were planned for less than or equal to five days and 9.1 percent of requested outages were planned for greater than 30 days in the first ten months of 2022/2023 planning period. Table 12-56 also shows that 77.3 percent of the requested outages were planned for less than or equal to five days and 8.1 percent of requested outages were planned for greater than 30 days in the 2021/2022 planning period.

Table 12-56 Transmission facility outage request summary by planned duration: June 2021 through March 2023

	2021/2022 (12 months)		2022/2023 (10 months)	
Planned Duration (Days)	Outage Requests	Percent of Total	Outage Requests	Percent of Total
<=5	15,182	77.3%	11,958	76.4%
>5 & <=30	2,869	14.6%	2,274	14.5%
>30	1,587	8.1%	1,419	9.1%
Total	19,638	100.0%	15,651	100.0%

After receiving a transmission facility outage request from a TO, PJM assigns a received status to the request based on its submission date and outage planned duration. The received status can be On Time or Late, as defined in Table 12-57.[135]

The purpose of the rules defined in Table 12-57 is to require the TOs to submit transmission facility outages prior to the Financial Transmission Right (FTR) auctions so that market participants have complete information about market conditions on which to base their FTR bids and PJM can accurately model market conditions.[136]

134 *Id.* at 70.
135 See PJM, "Manual 3: Transmission Operations," Rev. 63 (November 16, 2022).
136 See "*Report of PJM Interconnection, L.L.C. on Transmission Oversight Procedures*," Docket No. EL01-122-000 (November 2, 2001).

Table 12-57 Transmission facility outage request received status definition

Planned Duration (Calendar Days)	Request Submitted	Received Status
<=5	Before the first of the month one month prior to the starting month of the outage	On Time
	After or on the first of the month one month prior to the starting month of the outage	Late
> 5 & <=30	Before the first of the month six months prior to the starting month of the outage	On Time
	After or on the first of the month six months prior to the starting month of the outage	Late
>30	Before the earlier of 1) February 1, 2) the first of the month six months prior to the starting month of the outage	On Time
	After or on the earlier of 1) February 1, 2) the first of the month six months prior to the starting month of the outage	Late

Table 12-58 shows a summary of requests by received status. In the first ten months of the 2022/2023 planning period, 39.2 percent of outage requests received were late. In the 2021/2022 planning period, 40.1 percent of outage requests received were late.

Table 12-58 Transmission facility outage requests by received status: June 2021 through March 2023

	2021/2022 (12 months)				2022/2023 (10 months)			
Planned Duration (Days)	On Time	Late	Total	Percent Late	On Time	Late	Total	Percent Late
<=5	9,607	5,575	15,182	36.7%	7,731	4,227	11,958	35.3%
>5 & <=30	1,555	1,314	2,869	45.8%	1,210	1,064	2,274	46.8%
>30	602	985	1,587	62.1%	579	840	1,419	59.2%
Total	11,764	7,874	19,638	40.1%	9,520	6,131	15,651	39.2%

Once received, PJM processes outage requests in priority order: emergency transmission outage request; transmission outage request submitted on time; and transmission outage request submitted late. Transmission outage requests that are submitted late may be approved if the outage does not affect the reliability of PJM or cause congestion in the system.[137]

137 See PJM, "Manual 3: Transmission Operations," Rev. 63 (November 16, 2022). The following language was removed from Manual 3 Rev. 50: PJM retains the right to deny all jobs submitted after 8 a.m. three days prior to the requested start date unless the request is an emergency job or an exception request (i.e. a generator tripped and the Transmission Owner is taking advantage of a situation that was not available before the unit trip).

Outages with emergency status will be approved even if submitted late after PJM determines that the outage does not result in Emergency Procedures. PJM cancels or withholds approval of any outage that results in Emergency Procedures.[138] Table 12-59 is a summary of outage requests by emergency status. Of all outage requests scheduled to occur in the first ten months of the 2022/2023 planning period, 12.4 percent were for emergency outages. Of all outage requests scheduled to occur in the 2021/2022 planning period, 12.1 percent were for emergency outages.

Table 12-59 Transmission facility outage requests by emergency: June 2021 through March 2023

	2021/2022 (12 months)				2022/2023 (10 months)			
Planned Duration (Days)	Emergency	Non Emergency	Total	Percent Emergency	Emergency	Non Emergency	Total	Percent Emergency
<=5	1,748	13,434	15,182	11.5%	1,404	10,554	11,958	11.7%
>5 & <=30	356	2,513	2,869	12.4%	293	1,981	2,274	12.9%
>30	269	1,318	1,587	17.0%	242	1,177	1,419	17.1%
Total	2,373	17,265	19,638	12.1%	1,939	13,712	15,651	12.4%

PJM will approve all transmission outage requests that are submitted on time and do not jeopardize the reliability of the PJM system. PJM will approve all transmission outage requests that are submitted late and are not expected to cause congestion on the PJM system and do not jeopardize the reliability of the PJM system. Each outage is studied and if it is expected to cause a constraint to exceed a limit, PJM will flag the outage ticket as "congestion expected."[139]

After PJM determines that a late request may cause congestion, PJM informs the transmission owner of solutions available to eliminate the congestion. For example, if a generator planned or maintenance outage request is contributing to the congestion, PJM can request that the generation owner defer the outage. If no solutions are available, PJM may require the transmission owner to reschedule or cancel the outage.

Table 12-60 is a summary of outage requests by congestion status. Of all outage requests submitted to occur in the first ten months of the 2022/2023 planning

138 PJM, "Manual 3: Transmission Operations," Rev. 63 (November 16, 2022).
139 PJM added this definition to Manual 38 in February 2017. PJM, "Manual 38: Operations Planning," Rev. 16 (Jan. 25, 2023).

period, 8.0 percent were expected to cause congestion. Of all the outage requests that were expected to cause congestion, 3.6 percent (45 out of 1,256) were denied by PJM in the first ten months of the 2022/2023 planning period and 21.0 percent (264 out of 1,256) were cancelled (Table 12-62). Of all outage requests submitted to occur in the 2021/2022 planning period, 6.3 percent were expected to cause congestion. Of all the outage requests that were expected to cause congestion, 3.8 percent (47 out of 1,236) were denied by PJM in the 2021/2022 planning period and 19.6 percent (242 out of 1,236) were cancelled (Table 12-62).

Table 12-60 Transmission facility outage requests by congestion: June 2021 through March 2023

	2021/2022 (12 months)				2022/2023 (10 months)			
Planned Duration (Days)	Congestion Expected	No Congestion Expected	Total	Percent Congestion Expected	Congestion Expected	No Congestion Expected	Total	Percent Congestion Expected
<=5	918	14,264	15,182	6.0%	905	11,053	11,958	7.6%
>5 & <=30	211	2,658	2,869	7.4%	240	2,034	2,274	10.6%
>30	107	1,480	1,587	6.7%	111	1,308	1,419	7.8%
Total	1,236	18,402	19,638	6.3%	1,256	14,395	15,651	8.0%

Table 12-61 shows the outage requests summary by received status, congestion status and emergency status. In the first ten months of the 2022/2023 planning period, 27.0 percent of requests were submitted late and were nonemergency while 1.1 percent of requests (172 out of 15,651) were late, nonemergency, and expected to cause congestion. In the 2021/2022 planning period, 28.3 percent of request were submitted late and were nonemergency while 1.1 percent of requests (221 out of 19,638) were late, nonemergency, and expected to cause congestion.

Table 12-61 Transmission facility outage requests by received status, emergency and congestion: June 2021 through March 2023

		2021/2022 (12 months)				2022/2023 (10 months)			
Received Status		Congestion Expected	No Congestion Expected	Total	Percent of Total	Congestion Expected	No Congestion Expected	Total	Percent of Total
Late	Emergency	56	2,261	2,317	11.8%	59	1,853	1,912	12.2%
	Non Emergency	221	5,336	5,557	28.3%	172	4,047	4,219	27.0%
On Time	Emergency	8	48	56	0.3%	7	20	27	0.2%
	Non Emergency	951	10,757	11,708	59.6%	1,018	8,475	9,493	60.7%
Total		1,236	18,402	19,638	100.0%	1,256	14,395	15,651	100.0%

Once PJM processes an outage request, the outage request is labelled as Submitted, Received, Denied, Approved, Cancelled by Company, PJM Admin Closure, Revised, Active or Complete according to the processed stage of a request.[140] Table 12-62 shows the detailed process status for outage requests only for the outage requests that are expected to cause congestion. Status Submitted and status Received are in the In Process category and status Cancelled by Company and status PJM Admin Closure are in the Cancelled category in Table 12-62. Table 12-62 shows that of all the outage requests that were expected to cause congestion, 3.6 percent (45 out of 1,256) were denied by PJM in the first ten months of the 2022/2023 planning period, 63.9 percent were complete and 21.0 percent (264 out of 1,256) were cancelled. Of all the outage requests that were expected to cause congestion, 3.8 percent (47 out of 1,236) were denied by PJM in the 2021/2022 planning period, 67.6 percent were complete and 19.6 percent (242 out of 1,236) were cancelled.

140 See PJM Markets & Operations, PJM Tools "Outage Information," <http://www.pjm.com/markets-and-operations/etools/oasis/system-information/outage-info.aspx> (2019).

Table 12-62 Transmission facility outage requests by processed status[141]: June 2021 through March 2023

		2021/2022 (12 months)						2022/2023 (10 months)					
Received Status		Cancelled	Complete	In Process	Denied	Congestion Expected	Percent Complete	Cancelled	Complete	In Process	Denied	Congestion Expected	Percent Complete
Late	Emergency	7	47	0	1	56	83.9%	3	55	1	0	59	93.2%
	Non Emergency	36	159	3	22	221	71.9%	30	116	17	8	172	67.4%
On Time	Emergency	2	6	0	0	8	75.0%	0	6	1	0	7	85.7%
	Non Emergency	197	624	93	24	951	65.6%	231	626	112	37	1,018	61.5%
Total		242	836	96	47	1,236	67.6%	264	803	131	45	1,256	63.9%

There are clear rules defined for assigning On Time or Late status for submitted outage requests in both the PJM tariff and PJM manuals.[142] However, the On Time or Late status only affects the priority that PJM assigns for processing the outage request. Table 12-62 shows that in the 2021/2022 planning period, 221 nonemergency outage requests were submitted late and expected to cause congestion. The expected impact on congestion is the basis for PJM's treatment of late outage requests. But there is no rule or clear definition of this congestion analysis in the PJM manuals. The MMU recommends that PJM draft a clear definition of the congestion analysis required for transmission outage requests and associated triggers, including both the extent of overloaded facilities and the level of economic congestion, to include in Manual 3 after appropriate review.

The treatment by PJM and Dominion Virginia Power of the outage for the Lanexa – Dunnsville Line illustrates some of the issues with the current process. The outage was submitted and delayed more than once. It is not clear that PJM's analysis of expected congestion identified or highlighted the magnitude of the issue. Dominion Virginia Power did not stage the outage so as to minimize market disruption and congestion. After high congestion costs of Greys Point - Harmony Village constraint and market participant manipulative behavior caused by the outage were identified by the end of January, on February 11, 2022 Dominion decided to temporarily terminate the outage in March in order to work on upgrading Greys Point, Harmony Village and White Stone path. The Greys Point - Harmony Village Line has not been binding since March 14, 2022. It indicates that if the market impact of the outage was identified during PJM outage analysis process and action was taken because of the analysis result, the high congestion costs and manipulative behavior could have been prevented.

Rescheduling Transmission Facility Outage Requests

A TO can reschedule or cancel an outage after initial submission. Table 12-63 is a summary of all the outage requests planned for the 2021/2022 planning period and the first ten months of the 2022/2023 planning period which were approved and then cancelled or rescheduled by TOs at least once. If an outage request was submitted, approved and subsequently rescheduled at least once, the outage request will be counted as Approved and Rescheduled. If an outage request was submitted, approved and subsequently cancelled at least once, the outage request will be counted as Approved and Cancelled. In the first ten months of the 2022/2023 planning period, 27.2 percent of transmission outage requests were approved by PJM and then rescheduled by the TOs, and 10.8 percent of the transmission outages were approved by PJM and subsequently cancelled by the TOs. In the 2021/2022 planning period, 30.0 percent of transmission outage requests were approved by PJM and then rescheduled by the TO, and 12.5 percent of the transmission outages were approved by PJM and subsequently cancelled by the TO.

141 The number of denied transmission outage requests is lower than calculated by PJM the MMU includes only the transmission outage requests with "Denied" as a final status, while PJM included both transmission outage requests with "Denied" as a final status and transmission outage requests with "Denied" as an intermediate status.
142 OA Schedule 1 § 1.9.2.

Table 12-63 Rescheduled and cancelled transmission outage requests: June 2021 through March 2023

	2021/2022 (12 months)					2022/2023 (10 months)				
Planned Duration (Days)	Outage Requests	Approved and Rescheduled	Percent Approved and Rescheduled	Approved and Cancelled	Percent Approved and Cancelled	Outage Requests	Approved and Rescheduled	Percent Approved and Rescheduled	Approved and Cancelled	Percent Approved and Cancelled
<=5	15,182	3,187	21.0%	2,160	14.2%	11,958	2,280	19.1%	1,475	12.3%
>5 & <=30	2,869	1,590	55.4%	212	7.4%	2,274	1,176	51.7%	161	7.1%
>30	1,587	1,121	70.6%	89	5.6%	1,419	794	56.0%	54	3.8%
Total	19,638	5,898	30.0%	2,461	12.5%	15,651	4,250	27.2%	1,690	10.8%

If a requested outage is determined to be late and TO reschedules the outage, the outage will be revaluated by PJM again as On Time or Late.

A transmission outage ticket with duration of five days or less with an On Time status can retain its On Time status if the outage is rescheduled within the original scheduled month.[143] This rule allows a TO to reschedule within the same month with very little notice.

A transmission outage ticket with a duration exceeding five days with an On Time status can retain its On Time status if the outage is rescheduled to a future month, and the revision is submitted by the first of the month prior to the revised month in which the outage will occur.[144] This rescheduling rule is much less strict than the rule that applies to the first submission of outage requests with similar duration. When first submitted, the outage request with a duration exceeding five days needs to be submitted before the first of the month six months prior to the month in which the outage was expected to occur. The rescheduling rule allows TOs to avoid the timing requirements associated with outages exceeding five days.

The MMU recommends that PJM reevaluate all transmission outage tickets as on time or late as if they were new requests when an outage is rescheduled, create options for late requests based on the reasons, and apply the modified rules for late submissions to any such outages.

143 PJM, "Manual 3: Transmission Operations," Rev. 63 (November 16, 2022).
144 *Id.*

Long Duration Transmission Facility Outage Requests

PJM rules (Table 12-57) define a transmission outage request as On Time or Late based on the planned outage duration and the time of submission. The rule has stricter submission requirements for transmission outage requests planned for longer than 30 days. In order to avoid the stricter submission requirement, some transmission owners divided the duration of outage requests longer than 30 days into shorter segments for the same equipment and submitted one request for each segment. The MMU recommends that PJM not permit transmission owners to divide long duration outages into smaller segments to avoid complying with the requirements for long duration outages.

More than one outage request can be submitted for the same transmission equipment. In order to accurately present the results, Table 12-64 shows equipment outages by the equipment instead of by outage request.

Table 12-64 shows that there were 10,348 transmission equipment planned outages in the first ten months of the 2022/2023 planning period, of which 1,389 or 13.4 percent were longer than 30 days, and of which 174 or 1.7 percent were scheduled longer than 30 days when the duration of all the outage requests are combined for the same equipment.

Table 12-64 Transmission equipment outages: June 2021 through March 2023

		2021/2022 (12 months)		2022/2023 (10 months)	
Planned Duration (Days)	Divided into Shorter Periods	Count of Equipment with Planned Outages	Percent of Total	Count of Equipment with Planned Outages	Percent of Total
> 30	No	1,377	11.3%	1,215	11.7%
	Yes	238	2.0%	174	1.7%
<= 30		10,585	86.8%	8,959	86.6%
Total		12,200	100.0%	10,348	100.0%

Table 12-65 shows the details of long duration (> 30 days) outages when combining the duration of the outage requests for the same equipment.[145] The actual duration of scheduled outages would be longer than 30 days if the duration of the outage requests was appropriately combined for the same equipment. An effective duration was calculated for each piece of equipment by subtracting the start date of the earliest outage request from the end date of the latest outage request of the equipment. In the first ten months of the 2022/2023 planning period, within effective duration greater than a month and shorter than two months, there were 23 outages with a combined duration longer than 30 days.

Table 12-65 Transmission equipment outages by effective duration: June 2021 through March 2023

	2021/2022 (12 months)		2022/2023 (10 months)	
Effective Duration of Outage	Count of Equipment with Planned Outages	Percent of Total	Count of Equipment with Planned Outages	Percent of Total
<=31	3	1.3%	3	1.7%
>31 & <=62	29	12.2%	23	13.2%
>62 & <=93	20	8.4%	19	10.9%
>93	186	78.2%	129	74.1%
Total	238	100.0%	174	100.0%

Transmission Facility Outage Analysis for the FTR Market

Transmission facility outages affect the price and quantity outcomes of FTR Auctions. The purpose of the rules governing outage reporting is to ensure that outages are known with enough lead time prior to FTR Auctions so that market participants can understand market conditions and PJM can accurately model market conditions.

There are Long Term, Annual and Monthly Balance of Planning Period auctions in the FTR Market. For each type of auction, PJM includes a set of outages to be modeled.

145 A transmission facility is modeled as equipment in the EMS model. Equipment has three identifiers: location (B1), voltage level (B2) and equipment name (B3). The types of equipment include, for example, lines, transformers, and capacitors. There can be multiple outage requests associated with the same equipment.

Annual FTR Market

The Annual FTR Market includes the Annual ARR Allocation and the Annual FTR Auction. When determining transmission outages to be modeled in the simultaneous feasibility test used in the Annual FTR Market, PJM considers all outages with planned duration longer than or equal to two weeks as an initial list. Then PJM may exercise significant discretion in selecting outages to be modeled in the final model. PJM posts the final FTR outage list to the FTR web page usually at least one week before the auction bidding opening day.[146]

In the first ten months of the 2022/2023 planning period, 312 outage requests were included in the annual FTR market outage list and 15,339 outage requests were not included.[147] In the 2021/2022 planning period, 375 outage requests were included in the annual FTR market outage list and 19,263 outage requests were not included. Table 12-66, Table 12-67, Table 12-68 and Table 12-69 show the summary information on the modeled outage requests and Table 12-70 and Table 12-71 show the summary information on outages that were not included in the Annual FTR Market.

Table 12-66 shows that 21.8 percent of the outage requests modeled in the Annual FTR Market for the first ten months of the 2022/2023 planning period had a planned duration of less than two weeks and that 15.4 percent of the outage requests (48 out of 312) modeled in the Annual FTR Market for the planning period were submitted late according to outage submission rules. It also shows that 28.0 percent of the outage requests modeled in the Annual FTR Market for the 2021/2022 planning period had a planned duration of less than two weeks and that 16.8 percent of the outage requests (63 out of 375) modeled in the Annual FTR Market for the planning period were submitted late according to outage submission rules.

146 PJM Financial Transmission Rights, "Annual ARR Allocation and FTR Auction Transmission Outage Modeling," <https://www.pjm.com/-/media/markets-ops/ftr/annual-ftr-auction/2018-2019/2018-2019-annual-outage-modeling.ashx?la=en> (April 5, 2018). There is no documentation on the deadline for when modeling outages should be posted on the PJM website.

147 PJM's treatment of transmission outages in the FTR models is discussed in the *2022 State of the Market Report for PJM*: Section 13: FTRs and ARRs: Supply and Demand.

Table 12-66 Annual FTR market modeled transmission facility outage requests by received status: June 2021 through March 2023

	2021/2022 (12 months)				2022/2023 (10 months)			
Planned Duration	On Time	Late	Total	Percent of Total	On Time	Late	Total	Percent of Total
<2 weeks	90	15	105	28.0%	62	6	68	21.8%
>=2 weeks & <2 months	128	17	145	38.7%	86	10	96	30.8%
>=2 months	94	31	125	33.3%	116	32	148	47.4%
Total	312	63	375	100.0%	264	48	312	100.0%

Table 12-67 shows the annual FTR market modeled outage requests summary by emergency status and received status. Three of the annual FTR market modeled outages expected to occur in the first ten months of the 2022/2023 planning period were emergency outages. None of the modeled outages expected to occur in the 2021/2022 planning period were emergency outages.

Table 12-67 Annual FTR market modeled transmission facility outage requests by emergency: June 2021 through March 2023

		2021/2022 (12 months)				2022/2023 (10 months)			
Received Status	Planned Duration	Emergency	Non Emergency	Total	Percent Non Emergency	Emergency	Non Emergency	Total	Percent Non Emergency
On Time	<2 weeks	0	90	90	100.0%	0	62	62	100.0%
	>=2 weeks & <2 months	0	128	128	100.0%	0	86	86	100.0%
	>=2 months	0	94	94	100.0%	1	115	116	99.1%
	Total	0	312	312	100.0%	1	263	264	99.6%
Late	<2 weeks	0	15	15	100.0%	1	5	6	83.3%
	>=2 weeks & <2 months	0	17	17	100.0%	0	10	10	100.0%
	>=2 months	0	31	31	100.0%	2	30	32	93.8%
	Total	0	63	63	100.0%	3	45	48	93.8%

PJM determines expected congestion for both On Time and Late outage requests. A Late outage request may be denied or cancelled if it is expected to cause congestion. Table 12-68 shows a summary of requests by expected congestion and received status. Of all the annual FTR market modeled outages expected to occur in the first ten months of the 2022/2023 planning period and submitted late, 12.5 (6 out of 48) was expected to cause congestion. Overall, of all the annual FTR market modeled outages expected to occur in the 2021/2022 planning period and submitted late, 20.6 percent (13 out of 63) were expected to cause congestion.

Table 12-68 Annual FTR market modeled transmission facility outage requests by congestion: June 2021 through March 2023

		2021/2022 (12 months)				2022/2023 (10 months)			
Received Status	Planned Duration	Congestion Expected	No Congestion Expected	Total	Percent Congestion Expected	Congestion Expected	No Congestion Expected	Total	Percent Congestion Expected
On Time	<2 weeks	16	74	90	17.8%	16	46	62	25.8%
	>=2 weeks & <2 months	35	93	128	27.3%	12	74	86	14.0%
	>=2 months	19	75	94	20.2%	30	86	116	25.9%
	Total	70	242	312	22.4%	58	206	264	22.0%
Late	<2 weeks	2	13	15	13.3%	0	6	6	0.0%
	>=2 weeks & <2 months	7	10	17	41.2%	1	9	10	10.0%
	>=2 months	4	27	31	12.9%	5	27	32	15.6%
	Total	13	50	63	20.6%	6	42	48	12.5%

Table 12-69 shows that 25.0 percent of outage requests modeled in the annual FTR market for the first ten months of the 2022/2023 planning period and with a duration of two weeks or longer but shorter than two months were cancelled after the FTR auction was open, compared to 20.0 percent for the 2021/2022 planning period. Table 12-69 also shows that 18.9 percent of outages requests modeled in the Annual FTR Market for the first ten months of the 2022/2023 planning period and with a duration of two months or longer were cancelled, compared to 20.0 percent for the 2021/2022 planning period.

Table 12-69 Annual FTR market modeled transmission facility outage requests by processed status: June 2021 through March 2023

		2021/2022 (12 months)		2022/2023 (10 months)	
Planned Duration	Processed Status	Outage Requests	Percent	Outage Requests	Percent
<2 weeks	In Progress	11	10.5%	5	7.4%
	Denied	1	1.0%	0	0.0%
	Approved	1	1.0%	2	2.9%
	Cancelled	28	26.7%	26	38.2%
	Revised	0	0.0%	0	0.0%
	Active	0	0.0%	0	0.0%
	Completed	64	61.0%	35	51.5%
	Total	105	100.0%	68	100.0%
>=2 weeks & <2 months	In Progress	28	19.3%	15	15.6%
	Denied	1	0.7%	0	0.0%
	Approved	0	0.0%	0	0.0%
	Cancelled	29	20.0%	24	25.0%
	Revised	1	0.7%	0	0.0%
	Active	0	0.0%	3	3.1%
	Completed	86	59.3%	54	56.3%
	Total	145	100.0%	96	100.0%
>=2 months	In Progress	10	8.0%	25	16.9%
	Denied	0	0.0%	0	0.0%
	Approved	3	2.4%	2	1.4%
	Cancelled	25	20.0%	28	18.9%
	Revised	0	0.0%	0	0.0%
	Active	2	1.6%	41	27.7%
	Completed	85	68.0%	52	35.1%
	Total	125	100.0%	148	100.0%
Total Cancelled		82	21.9%	78	25.0%
Grand Total		375		312	

More outage requests were not modeled in the Annual FTR Market than were modeled in the Annual FTR Market. In the first ten months of the 2022/2023 planning period, 312 outage requests were modeled and 15,339 outage requests were not modeled in the Annual FTR Market. In the 2021/2022 planning period, 375 outage requests were modeled and 19,263 outage requests were not modeled in the Annual FTR Market.

Table 12-70 shows that 9.0 percent of outage requests not modeled in the Annual FTR Auction with duration longer than or equal to two months, labeled On Time according to the rules, were submitted or rescheduled after the Annual FTR Auction bidding opening date for the first ten months of the 2022/2023 planning period compared to 13.6 percent in the 2021/2022 planning period.

Table 12-70 Transmission facility outage requests not modeled in Annual FTR Auction: June 2021 through March 2023

	2021/2022 (12 months)						2022/2023 (10 months)					
	On Time			Late			On Time			Late		
Planned Duration	Before Bidding Opening Date	After Bidding Opening Date	Percent After	Before Bidding Opening Date	After Bidding Opening Date	Percent After	Before Bidding Opening Date	After Bidding Opening Date	Percent After	Before Bidding Opening Date	After Bidding Opening Date	Percent After
<2 weeks	1,925	8,360	81.3%	217	6,101	96.6%	1,838	6,394	77.7%	193	4,639	96.0%
>=2 weeks & <2 months	637	354	35.7%	128	795	86.1%	652	162	19.9%	128	597	82.3%
>=2 months	152	24	13.6%	197	373	65.4%	191	19	9.0%	217	309	58.7%
Total	2,714	8,738	76.3%	542	7,269	93.1%	2,681	6,575	71.0%	538	5,545	91.2%

Table 12-71 shows that 90.0 percent of late outage requests that were submitted after the Annual FTR Auction bidding opening date, were not modeled in the Annual FTR Auction, and had a duration longer than or equal to two months, were completed in the first ten months of the 2022/2023 planning period. It also shows that 91.2 percent of late outage requests which were not modeled in the Annual FTR Auction with duration longer than or equal to two months and submitted after the Annual FTR Auction bidding opening date were active or completed in the 2021/2022 planning period.

Table 12-71 Late transmission facility outage requests: June 2021 through March 2023

	2021/2022 (12 months)			2022/2023 (10 months)		
Planned Duration	Completed Outages	Total	Percent Complete	Completed Outages	Total	Percent Complete
<2 weeks	5,285	6,101	86.6%	4,032	4,639	86.9%
>=2 weeks & <2 months	696	795	87.5%	493	597	82.6%
>=2 months	340	373	91.2%	278	309	90.0%
Total	6,321	7,269	87.0%	4,803	5,545	86.6%

Although the definition of late outages was developed in order to prevent outages for the planning period being submitted after the opening of bidding in the Annual FTR Auction, the rules have not functioned effectively because the rule has no direct connection to the date on which bidding opens for the Annual FTR Auction. By requiring all long-duration transmission outages to be submitted before February 1, PJM outage submission rules only prevent long-duration transmission outages from being submitted late. The rule does not address the situation in which long-duration transmission outages are submitted on time, but are rescheduled so that they are late. There is no rule to address the situation in which short-duration outages (duration <= 5 days) are submitted on time, but are changed to long-duration transmission outages after the outages are approved and active. The Annual FTR Auction model may consider transmission outages planned for longer than two weeks but less than two months. Those outages not only include long duration outages but also include outages shorter than 30 days. In those cases, PJM outage submission rules failed to prevent those transmission outages from being submitted late. The MMU recommends that PJM create options for late requests based on the reasons, and modify the rules to reduce or eliminate the approval of late outage requests submitted or rescheduled after the FTR auction opening date, based on those options.

Monthly FTR Market

When determining transmission outages to be modeled in the Monthly Balance of Planning Period FTR Auction, PJM considers all outages with planned duration longer than five days and may consider outages with planned durations less than or equal to five days. PJM exercises significant discretion in selecting outages to be modeled. PJM posts an FTR outage list to the FTR webpage usually at least one week before the auction bidding opening day.[148] Table 12-72 and Table 12-73 show the summary information on outage requests modeled in the Monthly Balance of Planning Period FTR Auction and Table 12-74 and Table 12-75 show the summary information on outage requests not modeled in the Monthly Balance of Planning Period FTR Auction.

Table 12-72 shows that on average, 27.7 percent of the outage requests modeled in the Monthly Balance of Planning Period FTR Auction were submitted late according to outage submission rules in the first ten months of the 2022/2023 planning period. On average, 33.1 percent of the outage requests modeled in the Monthly Balance of Planning Period FTR Auction were submitted late according to outage submission rules in the 2021/2022 planning period.

Table 12-72 Monthly Balance of Planning Period FTR Auction modeled transmission facility outage requests by received status: June 2021 through March 2023

	2021/2022				2022/2023			
Month	On Time	Late	Total	Percent Late	On Time	Late	Total	Percent Late
Jun	209	116	325	35.7%	246	101	347	29.1%
Jul	103	85	188	45.2%	147	87	234	37.2%
Aug	125	81	206	39.3%	160	85	245	34.7%
Sep	363	147	510	28.8%	483	156	639	24.4%
Oct	480	192	672	28.6%	635	203	838	24.2%
Nov	454	205	659	31.1%	531	164	695	23.6%
Dec	325	153	478	32.0%	407	127	534	23.8%
Jan	214	118	332	35.5%	224	72	296	24.3%
Feb	216	121	337	35.9%	224	93	317	29.3%
Mar	399	142	541	26.2%	450	162	612	26.5%
Apr	454	172	626	27.5%				
May	402	182	584	31.2%				
Average	312	143	455	33.1%	351	125	476	27.7%

148 PJM Financial Transmission Rights, "2015/2016 Monthly FTR Auction Transmission Outage Modeling," <http://www.pjm.com/-/media/markets-ops/ftr/ftr-allocation/monthly-ftr-auctions/2015-2016-monthly-transmission-outages-that-may-cause-infeasibilities.ashx?la=en> (December 9, 2015).

Table 12-73 shows that on average, 18.9 percent of outage requests modeled in the Monthly Balance of Planning Period FTR Auction were cancelled in the first ten months of the 2022/2023 planning period. On average, 17.4 percent of outage requests modeled in the Monthly Balance of Planning Period FTR Auction were cancelled in the 2021/2022 planning period.

Table 12-73 Monthly Balance of Planning Period FTR Auction modeled transmission facility outage requests by processed status: June 2021 through March 2023

Planning Year	Month	In Process	Denied	Approved	Cancelled	Revised	Active	Complete	Total	Percent Cancelled
2021/2022	Jun	35	2	10	55	0	76	147	325	16.9%
	Jul	15	2	4	26	0	76	65	188	13.8%
	Aug	24	1	4	25	0	86	66	206	12.1%
	Sep	56	2	15	89	0	176	172	510	17.5%
	Oct	56	7	21	120	0	216	252	672	17.9%
	Nov	47	3	15	108	0	182	304	659	16.4%
	Dec	32	2	8	82	0	95	259	478	17.2%
	Jan	41	1	19	61	0	96	114	332	18.4%
	Feb	43	1	17	54	0	105	117	337	16.0%
	Mar	64	2	15	109	0	157	194	541	20.1%
	Apr	55	2	20	117	0	163	269	626	18.7%
	May	60	8	25	106	0	122	263	584	18.2%
	Average	44	3	14	79	0	129	185	455	17.4%
2022/2023	Jun	27	16	14	57	0	78	155	347	16.4%
	Jul	20	9	7	40	0	81	77	234	17.1%
	Aug	19	7	10	37	0	81	91	245	15.1%
	Sep	65	6	24	130	1	210	203	639	20.3%
	Oct	86	7	23	180	2	213	327	838	21.5%
	Nov	57	3	16	140	1	198	280	695	20.1%
	Dec	41	5	9	116	1	79	283	534	21.7%
	Jan	35	3	10	59	0	91	98	296	19.9%
	Feb	36	3	7	60	0	106	105	317	18.9%
	Mar	68	2	14	108	1	163	256	612	17.6%
	Average	45	6	13	93	1	130	188	476	18.9%

Table 12-74 shows that on average, 9.5 percent of outage requests not modeled in the Monthly Balance of Planning Period FTR Auction, labeled On Time according to the rules, were submitted after the monthly FTR auction bidding opening dates in the first ten months of the 2022/2023 planning period, compared to 9.3 percent in the 2021/2022 planning period. On average, 60.2 percent of outage requests not modeled in the Monthly Balance of Planning Period FTR Auction, labeled Late according to the rules, were submitted after the Monthly Balance of Planning Period FTR Auction bidding opening dates in the first ten months of the 2022/2023 planning period, compared to 61.7 percent in the 2021/2022 planning period.

Table 12-74 Transmission facility outage requests not modeled in Monthly Balance of Planning Period FTR Auction: June 2021 through March 2023

	2021/2022						2022/2023					
	On Time			Late			On Time			Late		
	Before Bidding Opening Date	After Bidding Opening Date	Percent After	Before Bidding Opening Date	After Bidding Opening Date	Percent After	Before Bidding Opening Date	After Bidding Opening Date	Percent After	Before Bidding Opening Date	After Bidding Opening Date	Percent After
Jun	776	87	10.1%	323	613	65.5%	754	162	17.7%	312	558	64.1%
Jul	349	69	16.5%	272	501	64.8%	366	82	18.3%	247	465	65.3%
Aug	365	49	11.8%	262	464	63.9%	402	73	15.4%	279	466	62.6%
Sep	934	105	10.1%	318	615	65.9%	957	64	6.3%	326	504	60.7%
Oct	1,035	77	6.9%	384	664	63.4%	1,090	72	6.2%	346	543	61.1%
Nov	860	50	5.5%	411	516	55.7%	952	71	6.9%	425	496	53.9%
Dec	673	34	4.8%	340	525	60.7%	743	53	6.7%	356	536	60.1%
Jan	563	85	13.1%	308	461	59.9%	657	44	6.3%	296	417	58.5%
Feb	696	69	9.0%	348	530	60.4%	679	47	6.5%	372	473	56.0%
Mar	1,289	78	5.7%	328	589	64.2%	1,324	69	5.0%	381	556	59.3%
Apr	1,524	119	7.2%	383	533	58.2%						
May	1,187	148	11.1%	419	573	57.8%						
Average	854	81	9.3%	341	549	61.7%	792	74	9.5%	334	501	60.2%

Table 12-75 shows that on average, 70.0 percent of late outage requests which were not modeled in the Monthly Balance of Planning Period FTR Auction, submitted after the Monthly Balance of Planning Period FTR Auction bidding opening dates, were approved and completed in the first ten months of the 2022/2023 planning period, compared to 70.2 percent in the 2021/2022 planning period.

Table 12-75 Late transmission facility outage requests: June 2021 through March 2023

	2021/2022			2022/2023		
	Completed Outages	Total	Percent Complete	Completed Outages	Total	Percent Complete
Jun	419	613	68.4%	408	558	73.1%
Jul	371	501	74.1%	354	465	76.1%
Aug	307	464	66.2%	335	466	71.9%
Sep	408	615	66.3%	349	504	69.2%
Oct	471	664	70.9%	380	543	70.0%
Nov	347	516	67.2%	325	496	65.5%
Dec	402	525	76.6%	395	536	73.7%
Jan	301	461	65.3%	267	417	64.0%
Feb	370	530	69.8%	306	473	64.7%
Mar	407	589	69.1%	400	556	71.9%
Apr	383	533	71.9%			
May	439	573	76.6%			
Average	385	549	70.2%	352	501	70.0%

Transmission Facility Outage Analysis in the Day-Ahead Energy Market

Transmission facility outages also affect the energy market. Just as with the FTR market, it is critical that outages that affect the operating day are known prior to the submission of offers in the day-ahead energy market so that market participants can understand market conditions and PJM can accurately model market conditions in the day-ahead market. PJM requires transmission owners to submit changes to outages scheduled for the next two days no later than 09:30 am.[149]

There are three relevant time periods for the analysis of the impact of transmission outages on the energy market: before the day-ahead market is closed; when the day-ahead market save cases are created; and during the operating day. The list of approved or active outage requests before the day-ahead market is closed is available to market participants. The day-ahead market model uses outages included in the day-ahead market save cases as an input. The outages that actually occurred during the operating day are the outages that affect the real-time market. If the three sets of outages are the same, there is no potential impact on markets. If the three sets of outages differ, there is a potential negative impact on markets. For example, if the list of outages before the day-ahead market was closed was different from the list of outages that included in the day-ahead market save cases, the day-ahead market participant would have inconsistent outage information as what day-ahead market model used.

For example for the operating day of May 5, 2018, Figure 12-7 shows that: there were 443 approved or active outages seen by market participants before the day-ahead market was closed; there were 329 outage requests included in the day-ahead market model; there were 315 outage requests included in both sets of outage; there were 128 outage requests approved or active before the day-ahead market was closed but not included as inputs in day-ahead market model; and there were 14 outage requests included in day-ahead market model but not available to market participants prior to the day-ahead market.

149 PJM, "Manual 3: Transmission Operations," Rev. 63 (November 16, 2022).

Figure 12-7 Illustration of day-ahead market analysis: May 5, 2018

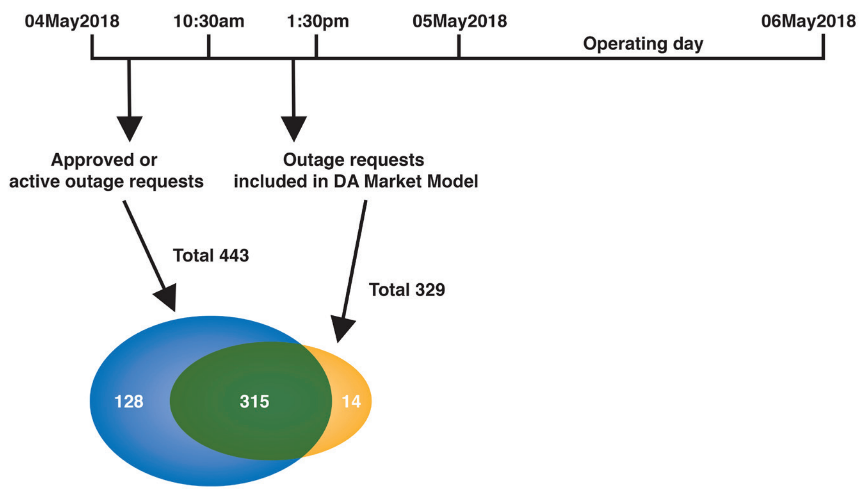


Figure 12-8 compares the weekly average number of active or approved outages available to market participants prior to the close of the day-ahead market with the outages included as inputs to the day-ahead market by PJM. Figure 12-8 shows that from the week of September 25, 2022, through the week of December 4, 2022, the number of outages included in the day-ahead market was closer to the number of outages for which information was available to market participants than previously. The average number of outages included in the day-ahead market increased from 256 outages (70.3 percent of average number of outages for which information was available to market participants) during the rest of weeks in 2022 to 449 outages (86.0 percent of average number of outages for which information was available to market participants) during the week of September 25, 2022, through the week of December 4, 2022.

Figure 12-8 Approved or active outage requests: January 2015 through March 2023

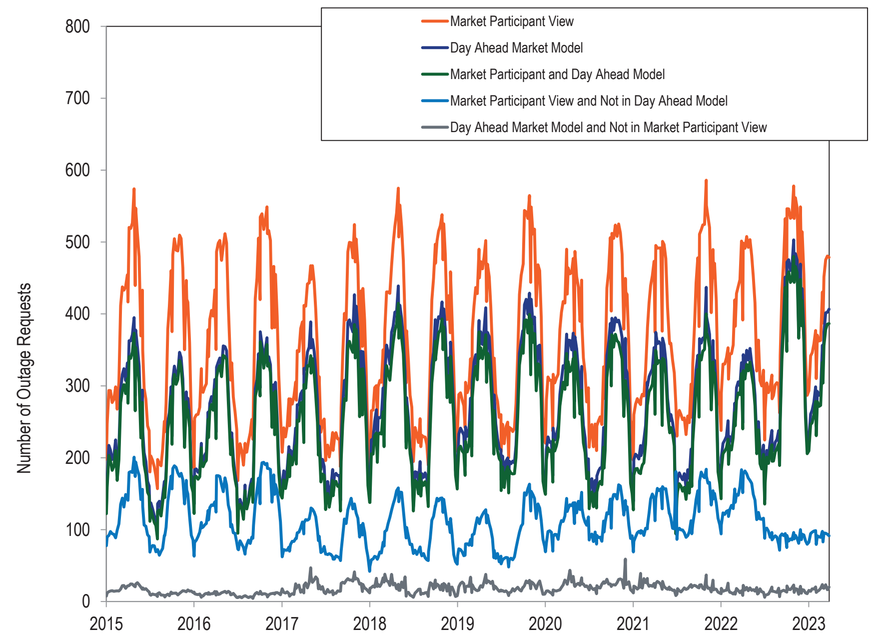


Figure 12-9 compares the weekly average number of outages included in the day-ahead market with the outages that actually occurred during the operating day. Figure 12-9 shows that starting on May 29, 2022, the weekly average number of outages included in the day-ahead market was consistently higher than the weekly average number of outages that actually occurred. The average number of outages included in the day-ahead market increased from 273 (95.6 percent of the average number of outages that actually occurred) from the week of January 1, 2015, through the week of May 22, 2022, to 315 (134.2 percent of average number of outages that actually occurred) for the period from the week of May 29, 2022, through the end of March 2023.

Figure 12-9 Day-ahead market model outages: January 2015 through March 2023

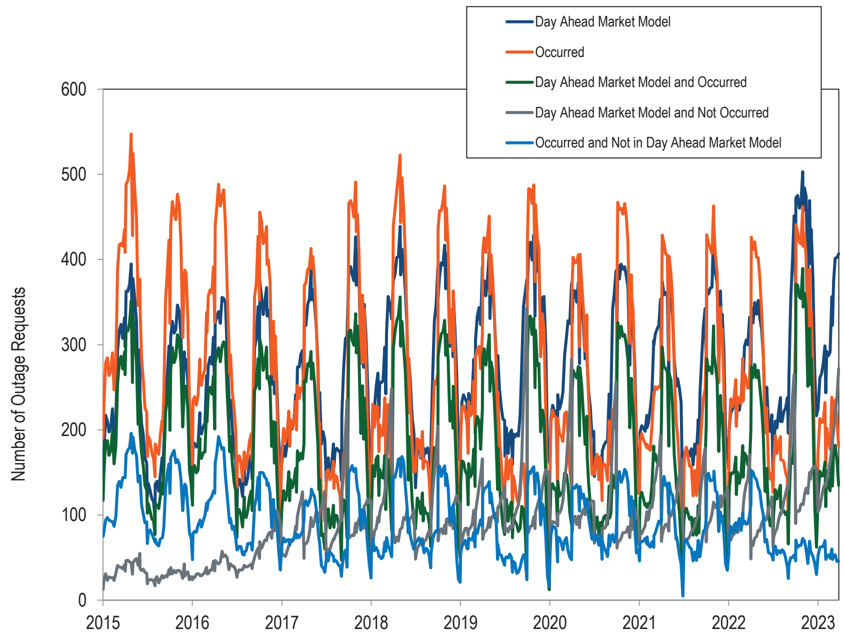


Figure 12-10 Approved or active outage requests: January 2015 through March 2023

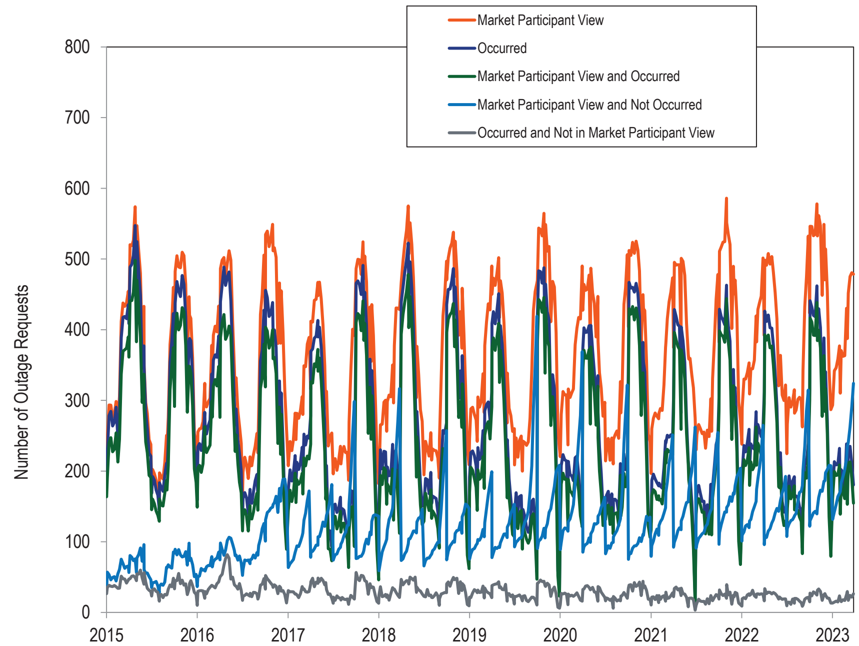


Figure 12-10 compares the weekly average number of active or approved outages for which information was available to market participants prior to the close of the day-ahead market with the outages that actually occurred during the operating day. The average number of outages that actually occurred were 74.0 percent of the average number of outages for which information was available to market participants.

Figure 12-8, Figure 12-9, and Figure 12-10 show that on a weekly average basis, for the full year 2022, the active or approved outages for which information was available to day-ahead market participants, the outages included as inputs in the day-ahead market model and the outages that actually occurred in real time are not consistent. The average number of outages that actually occurred were 74.0 percent of the average number of outages for which information was available to market participants. The average number of outages included in the day-ahead market were 74.3 percent of the average number of outages for which information was available to market participants.

Financial Transmission and Auction Revenue Rights

In an LMP market, the lowest cost generation is dispatched to meet the load, but when there are transmission constraints, load pays the high local price for all generation, including the low cost generation serving part of that load. The low cost generation receives payment only for its low local price and does not receive the payment made by load for the output of the low cost generation at the high local price. The result is that load pays the correct local price but pays too much in total for energy because it is paying more for the low cost generation than the low cost generation receives. Load pays the difference between the high local price and the low local price of the low cost generation. That payment is appropriately not made to the low cost generation which is paid its LMP. In an LMP market, load pays more than generation receives. FTRs are the mechanism for returning those excess payments to load. But the current FTR mechanism in PJM does not and cannot return all the excess payments to load. The FTR mechanism in PJM needs a significant redesign in order to achieve that objective. The FTR mechanism has become unduly complicated and has deviated significantly from its original purpose. Return of all the excess payments to load would result in a perfect hedge against congestion. The current FTR mechanism has significantly attenuated the value of the FTR/ARR design as a hedge against congestion for load.

The FTR mechanism should be a simple accounting method for assigning congestion rights to load. But PJM has added increasingly complex rules and regularly intervenes in the FTR mechanism as the PJM FTR design has moved further and further from these economic fundamentals. Some market participants have profited in various ways from these design flaws and those market participants now strongly defend the current design. The customers who ultimately pay congestion are generally not aware of the FTR design and do not understand the extent to which the design fails to offset their congestion payments.

When the lowest cost generation is remote from load centers, the physical transmission system permits that lowest cost generation to be delivered to load, subject to transmission limits. This was true prior to the introduction of LMP markets and continues to be true in LMP markets.

After the introduction of LMP markets, financial transmission rights (FTRs) were introduced, effective April 1, 1999, for the real-time market and June 1, 2000, for the combined day-ahead and balancing (real-time) markets. FTRs permitted the loads, which pay for the transmission system, to continue to receive the benefits of access to either local or remote low cost generation by returning congestion to the load.[1] FTRs and the associated congestion revenues were directly provided to load in recognition of the fact that, as a result of LMP, load was required to pay more for low cost generation than is paid to low cost generation. But there was a flaw built in from the very beginning of the FTR design that had no significant impact initially but which was ultimately the source of all the issues with the FTR mechanism. That flaw was the idea that congestion was based on contract paths in a network system rather than a result of the actual operation of the complex network. Prior to the introduction of LMP markets, payment for the delivery of low cost generation to load was based both on intrazonal generation and intrazonal transmission, both under cost of service rates, and on contracts with specific remote generation outside the local zone and the associated point to point transmission contracts. But most load was served by intrazonal generation. In both cases, customers paid for the physical rights associated with the transmission system used to provide for the delivery of low cost generation to load. There was no congestion revenue because customers paid only the actual cost of the low cost generation. The flawed idea that congestion is based on contract paths was inconsistent with the most basic logic of LMP and the resultant fissure has continued to widen. The origin of FTRs was the recognition that the way to hold load harmless from making the excess payments created by the LMP system was to return the excess payments to load. The rights to congestion belong to load. If implemented correctly, FTRs would be the financial equivalent of firm transmission service for load. If implemented correctly, FTRs would be a perfect hedge against congestion for load. The result of the current FTR mechanism is a significant reduction in the value of FTRs as a hedge for load.

1 See 81 FERC ¶ 61,257 at 62,241 (1997).

The notion that FTRs exist in order to provide a hedge for generation is a fallacy. In an LMP system, the basic incentive structure for generation derives from the fact that generation is paid the LMP at the generator bus. If generation were to be guaranteed a price at a distant constrained load bus rather than at the generation bus, there would be no incentive for generation to locate where it is needed on the system. In addition, the payment of the price at the generator bus is fundamental to the logic of locational marginal pricing which produces local prices equal to the marginal value of generation at every point. There is no logical or theoretical basis in locational marginal pricing for the assertion that generation at low price nodes is underpaid and should be paid more from congestion dollars. Generation does not pay congestion. Some generation receives a price lower than the system marginal price (SMP) and some generation receives a price greater than SMP, but that does not mean that generation is paying congestion. It means that generation is being paid an LMP that is higher or lower than the system load-weighted average LMP. If a generating unit wants a hedge, it may enter into an arm's length transaction with a willing counter party as a hedge. That is the way hedges work in markets. That is not the purpose of FTRs.

In an LMP system, the only way to ensure that load receives the benefits associated with the use of the transmission system to deliver low cost energy is to use FTRs, or an equivalent mechanism, to pay back to load the difference between the total load payments and the total generation revenues. FTRs were the mechanism selected in PJM to offset the congestion costs that load pays in an LMP market. Congestion revenues are the source of the funds to pay FTRs. Congestion revenues are assigned to the load that paid them through FTRs.[2] The only way to ensure that load receives the benefits associated with the use of the transmission system to deliver low cost energy is to ensure that all congestion revenues are returned to load or, more precisely, that the rights to all congestion revenues are assigned to load. In order to do that, congestion must be defined correctly based on the operation of the network and not on arbitrary contract paths.

Effective April 1, 1999, when FTRs were introduced with the LMP market, there was a real-time market but no day-ahead market, and FTRs returned real-time congestion revenue to load. Effective June 1, 2000, the day-ahead market was introduced and FTRs returned total congestion including day-ahead and balancing (real-time) congestion to load. Congestion, in PJM's two settlement market, is the sum of day-ahead and balancing congestion. Effective June 1, 2003, PJM replaced the direct allocation of FTRs to load with an allocation of Auction Revenue Rights (ARRs). Under the ARR design, the load still owns the rights to congestion revenue, but the ARR design allows load to either claim the FTRs directly (through a process called self scheduling), or to sell the rights to congestion revenue in the FTR auction in exchange for a revenue stream based on the auction clearing prices of the FTRs. Under the ARR design, the right to all congestion revenues should belong to load. All congestion surplus should be assigned to load. But the actual implementation produces a very different result.

ARRs were an add on concept, defined based on a misunderstanding of FTRs, which had its roots in the assignment of congestion to load using contract paths (generation to load paths) rather than on the calculation of congestion actually paid. ARRs used assumed contract paths to assign congestion to load. The use of contract paths for ARRs was a more critical mistake than using contract paths for FTRs because contract paths did not and do not account for all congestion. The use of contract paths led to the mistaken conclusion that some congestion did not belong to load and could be sold to FTR buyers. The ARR concept, as it is currently implemented, does not allow the FTR sellers, load, to establish a price at which they are willing to sell, but forces load to accept whatever prices buyers are willing to pay. The revenue from the sale of congestion rights is not even paid in full to ARR holders. Sellers are required to return some of the cleared auction revenue to FTR buyers when FTR payments are less than target allocations. So called surplus revenue is paid to FTR holders to ensure payment, despite the fact that willing FTR buyers paid the revenues in the auction for the rights to an uncertain level of congestion.

The use of generation to load contract paths, rather than the direct calculation of congestion, led to an increased divergence between FTR target allocations on the generation to load contract paths and actual total congestion. This

2 See *id.* at 62, 259–62,260 & n. 123.

divergence between actual network use and historic contract paths was exacerbated as new zones were added with their own historic generation to load contract paths and as significant numbers of generating units retired and new units were added.[3] Rather than understanding that the divergence resulted from the fact that a contract path based approach did not correctly calculate congestion in a network system, especially as the system grew significantly, the issue was characterized as the existence of excess capacity on the transmission system. But congestion was never about capacity on the transmission system. Prior to the introduction of ARRs, the so called excess congestion that exceeded the congestion on the defined contract paths was returned to load, regardless of its source. There is no such thing as excess congestion. The overlay of ARRs on the FTR concept did not change the fundamental logic of congestion, but permitted the introduction of a system in which the divergence was formally created between the amount of congestion paid by load and the amount of congestion returned to load. Congestion belongs to the load, by definition. The introduction of ARRs based on a contract path fiction undermined the assignment of all congestion rights to load.

The contract path fiction is also the source of the incorrect definition of the product that is bought and sold as FTRs, the available supply of the product and the price paid to the buyers of the product. The product is defined as the difference in congestion prices across specific transmission contract paths. The difference in congestion prices across contract paths is not congestion and is not equal to congestion revenues. The quantity of the product made available for sale in the FTR auctions is defined as system capability, meaning the capacity of the transmission system to deliver power. But system capability is not congestion and system capability is not the difference in congestion prices across transmission contract paths nor the potential for such difference. The definition of ARRs based on contract paths led to the mistaken idea that some transmission system capacity was used by ARRs but some was not and that both the ARR capability and the excess capability was available for sale as FTRs. This fundamental confusion in the design of the market is the source of so called revenue shortfalls, of the redesign of the market to exclude balancing congestion, and of the need for PJM to intervene in the market. PJM has had to regularly intervene in the market because the market as designed cannot reach equilibrium based on the economic fundamentals. The product, the quantity of the product, and the price of the product are all incorrectly defined.

The ARR/FTR design does not serve as an efficient mechanism for returning congestion to load, as a result of an FTR design that was flawed from its introduction and as a result of various distortions added to the design since its introduction. The distortions include the definition of target allocations based on day-ahead congestion only, the fact that ARR holders cannot set the sale price for congestion revenue rights, the return of market revenues to FTR buyers when profit targets are not met, the failure to assign all FTR auction revenues to ARR holders, the differences between modeled and actual system capability, the definition and allocation of surplus, and the numerous cross subsidies among participants. The fundamental distortion was the assignment of the rights to congestion revenue based on specific generation to load transmission contract paths. This approach retained the contract path based view of congestion rooted in physical transmission rights and inconsistent with the role of FTRs in a nodal, network system with locational marginal pricing.

The cumulative offset by ARRs for the 2011/2012 planning period through the first ten months of the 2022/2023 planning period, using the rules effective for each planning period, was 69.0 percent. Load has been underpaid by $3.8 billion from the 2011/2012 planning period through the first ten months of the 2022/2023 planning period. The 31.5 percent share of congestion offset by ARRs and self-scheduled FTRs in the 2021/2022 planning period was the lowest offset to congestion since PJM implemented ARRs.

The overall underassignment of congestion to load includes dramatically different results by zone. Load in some zones receives congestion revenues well in excess of the congestion they pay while the reverse is true for other zones.

3 For a comprehensive report on capacity retirements and capacity additions in PJM, see: "2020 PJM Generation Capacity and Funding Sources: 2007/2008 through 2021/2022," (September 15, 2020) available at <http://www.monitoringanalytics.com/reports/Reports/2020/Constraint_Based_Congestion_Calculations_20200722.pdf>.

If the original PJM FTR approach had been designed to return congestion revenues to load without use of the generation to load contract paths, and if the distortions subsequently introduced into the FTR design had not been added, many of the subsequent issues with the FTR design and complex redesigns would have been avoided. PJM would not have had to repeatedly intervene in the functioning of the FTR system in an effort to meet the artificial and incorrectly defined goal of revenue adequacy. The design should simply have provided for the return of all congestion revenues to load. The design should have also provided for the ability of load to sell the rights to congestion revenue. That sale could be organized as an FTR auction with the product and the price clearly defined. Now is a good time to address the issues of the FTR design and to return the design to its original purpose. This would eliminate much of the complexity associated with ARRs and FTRs and eliminate unnecessary controversy about the appropriate recipients of congestion revenues.

The 2023 Quarterly State of the Market Report for PJM: January through March focuses on the 2022/2023 Monthly Balance of Planning Period FTR Auctions, specifically covering January 1, 2023, through March 31, 2023. The Market Monitoring Unit (MMU) analyzed measures of market structure, participant conduct and market performance, including market size, concentration, offer behavior, and price. The MMU concludes that the PJM FTR auction market results were partially competitive in the first three months of 2023.

Table 13-1 The FTR/ARR markets results were partially competitive

Market Element	Evaluation	Market Design
Market Structure	Competitive	
Participant Behavior	Partially Competitive	
Market Performance	Partially Competitive	Flawed

- Market structure was evaluated as competitive. The ownership of FTR obligations is unconcentrated for the individual years of the 2022/2025 Long Term FTR Auction, the 2022/2023 Annual FTR Auction and each period of the Monthly Balance of Planning Period Auctions. The ownership of FTR options is moderately or highly concentrated for every Monthly FTR Auction period and moderately concentrated for the 2022/2023 Annual FTR Auction. Ownership of FTRs is disproportionately (75.2 percent) by financial participants. The ownership of ARRs is unconcentrated.
- Participant behavior was evaluated as partially competitive because ARR holders who are the sellers of FTRs are not permitted to participate in the market clearing.
- Market performance was evaluated as partially competitive because of the flaws in the market design. Sellers, the ARR holders, cannot set a sale price. Buyers can reclaim some of their purchase price after the market clears if the product does not meet a profitability target. The market resulted in a substantial shortfall in congestion payments to load and significant and unsupportable disparities among zones in the share of congestion returned to load. FTR purchases by financial entities remain persistently profitable in part as a result of the flaws in the market design.
- Market design was evaluated as flawed because there are significant and fundamental flaws with the basic ARR/FTR design. The FTR auction market is not actually a market because the sellers have no independent role in the process. ARR holders cannot determine the price at which they are willing to sell rights to congestion revenue. Buyers have the ability to reclaim some of the price paid for FTRs after the market clears. The market design is not an efficient or effective way to ensure that the rights to all congestion revenues are assigned to load. The product sold to FTR buyers is incorrectly defined as target allocations rather than a share of congestion revenue. ARR holders' rights to congestion revenues are not correctly defined because the contract path based assignment of congestion rights is inadequate and incorrect. Ongoing PJM subjective intervention in the FTR market that affects market fundamentals is also an issue and a symptom of the fundamental flaws in the design. The product, the quantity of the product and the price of the product are all incorrectly defined.
- The fact that load is not able to define its willingness to sell FTRs or the prices at which it is willing to sell FTRs and the fact that sellers are required to return some of the cleared auction revenue to FTR buyers when FTR profits are not adequate, means that the FTR design does not

actually function as a market and is evidence of basic flaws in the market design.

Overview

Auction Revenue Rights

Market Structure

- **ARR Ownership.** In the 2022/2023 planning period ARRs were allocated to 1,563 individual participants, held by 133 parent companies. ARR ownership for the 2022/2023 planning period was unconcentrated with an HHI of 584.

Market Behavior

- **Self Scheduled FTRs.** For the 2022/2023 planning period, 26.0 percent of eligible ARRs were self scheduled as FTRs.

Market Performance

- **ARRs as an Offset to Congestion.** ARRs have not served as an effective mechanism to return all congestion revenues to load. For the first ten months of the 2022/2023 planning period, ARRs and self scheduled FTRs offset 75.6 percent of total congestion. Congestion payments by load in some zones were more than offset and congestion payments in some zones were less than offset. Load has been underpaid congestion revenues by $3.8 billion from the 2011/2012 planning period through the first ten months of the 2022/2023 planning period. The cumulative offset for that period was 69.0 percent of total congestion.
- **ARR Payments.** For the first ten months of the 2022/2023 planning period, the ARR target allocations, which are based on the nodal price differences from the Annual FTR Auction, were $1,343.2 million, while PJM collected $1,660.4 million from the combined Long Term, Annual and Monthly Balance of Planning Period FTR Auctions. For the 2021/2022 planning period, the ARR target allocations were $634.2 million while PJM collected $812.6 million from the combined Annual and Monthly Balance of Planning Period FTR Auctions.
- **Residual ARRs.** Residual ARRs are only available on contract paths prorated in Stage 1 of the annual ARR allocation, are only effective for single, whole months and cannot be self scheduled. Residual ARR clearing prices are based on monthly FTR auction clearing prices. Residual ARRs with negative target allocations are not allocated to participants. Instead they are removed and the model is rerun.

  In the first ten months of the 2022/2023 planning period, PJM allocated a total of 27,924.0 MW of residual ARRs with a total target allocation of $31.0 million, up from 24,023.5 MW, with a total target allocation of $16.2 million, in the same period of the 2021/2022 planning period.
- **ARR Reassignment for Retail Load Switching.** There were 30,917 MW of ARRs associated with $1,325,600 of revenue that were reassigned for the first ten months of the 2022/2023 planning period. There were 32,935 MW of ARRs associated with $568,200 of revenue that were reassigned in the 2021/2022 planning period.

Financial Transmission Rights

Market Design

- **Monthly Balance of Planning Period FTR Auctions.** The design of the Monthly Balance of Planning Period FTR Auctions includes auctions for each remaining month in the planning period.

Market Structure

- **Patterns of Ownership.** For the Monthly Balance of Planning Period Auctions, financial entities purchased 83.1 percent of prevailing flow and 92.4 percent of counter flow FTRs in the first three months of 2023. Financial entities owned 75.2 percent of all prevailing and counter flow FTRs, including 64.3 percent of all prevailing flow FTRs and 87.1 percent of all counter flow FTRs during the first three months of 2023. Self scheduled FTRs account for 4.8 percent of all FTRs held.

- **Market Concentration.** In the Monthly Balance of Planning Period Auctions for the first ten months of the 2022/2023 planning period, ownership of cleared prevailing flow bids was unconcentrated in 93.3 percent of periods and moderately concentrated in 6.7 percent of periods. Ownership of cleared counter flow bids was unconcentrated in 66.7 percent of periods and moderately concentrated in 33.3 percent of periods.

Market Behavior

- **Sell Offers.** In a given auction, market participants can sell FTRs acquired in preceding auctions or preceding rounds of auctions. In the Monthly Balance of Planning Period FTR Auctions for the first ten months of the 2022/2023 planning period, total participant FTR sell offers were 20,815,305 MW.
- **Buy Bids.** The total FTR buy bids from the Monthly Balance of Planning Period FTR Auctions for the first ten months of the 2022/2023 planning were 37,743,885 MW.
- **FTR Forfeitures.** Total FTR forfeitures were $3.4 million for the first ten months of the 2022/2023 planning period.
- **Credit.** There was one collateral default and zero payment defaults in the first three months of 2023. Market Performance.
- **Quantity** In the first ten months of the 2022/2023 planning period, Monthly Balance of Planning Period FTR Auctions cleared 6,672,139 MW (17.7 percent) of FTR buy bids and 3,231,664 MW (15.5 percent) of FTR sell offers. For the same period of the 2021/2022 planning period, Monthly Balance of Planning Period FTR Auctions cleared 5,254,0456 MW (19.3 percent) of FTR buy bids and 2,971,061 MW (19.9 percent) of FTR sell offers.
- **Price.** The weighted average buy bid cleared FTR price in the Monthly Balance of Planning Period FTR Auctions for all periods in the first ten months of the 2022/2023 planning period was $0.49 per MWh.
- **Revenue.** The Monthly Balance of Planning Period FTR Auctions resulted in net revenue of $102.2 million in the first ten months of the 2022/2023 planning period, up from $46.1 million for the same time period in the 2021/2022 planning period.
- **Revenue Adequacy.** FTRs were paid 100.0 percent of the target allocations for the first ten months of the 2022/2023 planning period, including distribution of the current surplus revenue.
- **Profitability.** FTR profitability is the difference between the revenue received directly from holding an FTR plus any revenue from the sale of an FTR, and the cost of buying the FTR. In the first 10 months of the 2022/2023 planning period, profits for all participants were $393.1 million. In the first 10 months of the 2022/2023 planning period, physical entities received $23.5 million in profits on FTRs purchased directly (not self scheduled), down from $201.3 million in profits in the same time period in the 2021/2022 planning period. Financial entities received $369.6 million in profits, down from $598.4 million profits in the same time period in the 2021/2022 planning period.

Markets Timeline

Any PJM member can participate in the Long Term FTR Auction, the Annual FTR Auction and the Monthly Balance of Planning Period FTR Auctions.

Table 13-2 shows the date of first availability and final closing date for all annual ARR and FTR products.

Table 13-2 Annual FTR product dates

Auction	Initial Open Date	Final Close Date
2023/2026 Long Term	6/2/2022	3/3/2023
2022/2023 ARR	2/28/2022	3/29/2022
2022/2023 Annual	4/5/2022	4/28/2022
2024/2027 Long Term	6/1/2023	3/1/2024
2023/2024 ARR	3/1/2023	3/24/2023
2023/2024 Annual	4/4/2023	4/27/2023

Recommendations

Market Design

- The MMU recommends that the current ARR/FTR design be replaced with defined congestion revenue rights (CRRs). A CRR is the right to actual congestion that is paid by physical load at a specific bus, zone or aggregate. (Priority: High. First reported 2015. Status: Not adopted.)

ARR

- The MMU recommends that the ARR/FTR design be modified to ensure that the rights to all congestion revenues are assigned to load. (Priority: High. First reported 2015. Status: Not adopted.)
- The MMU recommends that all historical generation to load paths be eliminated as a basis for assigning ARRs. The MMU recommends that the current design be replaced with a design in which the rights to actual congestion paid are assigned directly to the load that paid that congestion by node. (Priority: High. First reported 2015. Status: Partially adopted.)
- The MMU recommends that, under the current FTR design, the rights to all congestion revenue be allocated as ARRs prior to sale as FTRs. Reductions for outages and increased system capability should be reserved for ARRs rather than sold in the Long Term FTR Auction. (Priority: High. First reported 2017. Status: Not adopted.)
- The MMU recommends that IARRs be eliminated from PJM's tariff, but that if IARRs are not eliminated, IARRs should be subject to the same proration rules that apply to all other ARR rights. (Priority: Low. First reported 2018. Status: Not adopted.)

FTR

- The MMU recommends that FTR funding be based on total congestion, including day-ahead and balancing congestion. (Priority: High. First reported 2017. Status: Not adopted.)
- The MMU recommends that bilateral transactions be eliminated and that all FTR transactions occur in the PJM market. (Priority: High. First reported Q1 2022. Status: Not adopted.)[4]
- The MMU recommends a requirement that the details of all bilateral FTR transactions be reported to PJM. (Priority: High. First reported 2020. Status: Not adopted.)
- The MMU recommends that PJM continue to evaluate the bilateral indemnification rules and any asymmetries they may create. (Priority: Low. First reported 2018. Status: Not adopted.)
- The MMU recommends that PJM reduce FTR sales on paths with persistent overallocation of FTRs, including a clear definition of persistent overallocation and how the reduction will be applied. (Priority: High. First reported 2013. Status: Partially adopted, 2014/2015 planning period.)
- The MMU recommends that PJM eliminate generation to generation paths and all other paths that do not represent the delivery of power to load. (Priority: High. First reported 2018. Status: Not adopted.)
- The MMU recommends that the Long Term FTR product be eliminated. If the Long Term FTR product is not eliminated, the Long Term FTR Market should be modified so that the supply of prevailing flow FTRs in the Long Term FTR Market is based solely on counter flow offers in the Long Term FTR Market. (Priority: High. First reported 2017. Status: Not adopted.)
- The MMU recommends that PJM improve transmission outage modeling in the FTR auction models, including the use of probabilistic outage modeling. (Priority: Low. First reported 2013. Status: Not adopted.)

Surplus

- The MMU recommends that all FTR auction revenue be distributed to ARR holders monthly, regardless of FTR funding levels. (Priority: High. First reported 2015. Status: Not adopted.)
- The MMU recommends that, under the current FTR design, all congestion revenue in excess of FTR target allocations be distributed to ARR holders on a monthly basis. (Priority: High. First reported 2018. Status: Not adopted.)

4 If adopted, this recommendation would replace the next two recommendations.

- The MMU recommends that FTR auction revenues not be used by PJM to buy counter flow FTRs for the purpose of improving FTR payout ratios.[5] (Priority: High. First reported 2015. Status: Not adopted.)

FTR Subsidies

- The MMU recommends that PJM eliminate portfolio netting to eliminate cross subsidies among FTR market participants. (Priority: High. First reported 2012. Status: Not adopted. Rejected by FERC.)
- The MMU recommends that PJM eliminate subsidies to counter flow FTRs by applying the payout ratio to counter flow FTRs in the same way the payout ratio is applied to prevailing flow FTRs. (Priority: High. First reported 2012. Status: Not adopted.)
- The MMU recommends that PJM eliminate geographic cross subsidies. (Priority: High. First reported 2013. Status: Not adopted.)
- The MMU recommends that PJM examine the mechanism by which self scheduled FTRs are allocated when load switching among LSEs occurs throughout the planning period. (Priority: Low. First reported 2011. Status: Not adopted.)

FTR Liquidation

- The MMU recommends that the FTR portfolio of a defaulted member be canceled rather than liquidated or allowed to settle as a default cost on the membership. (Priority: High. First reported 2018. Status: Not adopted.)

Credit

- The MMU recommends the use of a 99 percent confidence interval when calculating initial margin requirements for FTR market participants, in order to assign the cost of managing risk to the FTR holders who benefit or lose from their FTR positions. (Priority: High. First reported 2021. Status: Not adopted.)

5 See "PJM Manual 6: Financial Transmission Rights," Rev. 29 (Sep. 1, 2022).

Conclusion

Solutions

The annual ARR allocation should be designed to ensure that the rights to all congestion revenues are assigned to load, without requiring contract path or point to point physical or financial transmission rights that are inconsistent with the network based delivery of power and the actual way congestion is generated in security constrained LMP markets. When there are binding transmission constraints and locational price differences, load pays more for energy than generation is paid to produce that energy. The difference is congestion. As a result, congestion belongs to load and should be returned to load.

The current contract path based design should be replaced with a design in which the rights to actual congestion paid are assigned directly to the load that paid that congestion by node. The assigned right is to the actual difference between load payments, both day-ahead and balancing, and revenues paid to the generation used to serve that load. The load can retain the right to the congestion revenues or sell the rights through auctions. The correct assignment of congestion revenues to load is fully consistent with retaining FTR auctions for the sale by load of their congestion revenue rights.

Issues

If the original PJM FTR approach had been designed to return congestion revenues to load without use of the generation to load contract paths, and if the distortions subsequently introduced into the FTR design not been added, many of the subsequent issues with the FTR design and complex redesigns would have been avoided. PJM would not have had to repeatedly intervene in the functioning of the FTR system in an effort to meet the artificial and incorrectly defined goal of revenue adequacy.

PJM has persistently and subjectively intervened in the FTR market in order to affect the payments to FTR holders. These interventions are not appropriate. For example, in the 2014/2015, 2015/2016 and 2016/2017 planning periods, PJM significantly reduced the allocation of ARR capacity, and FTRs, in order to guarantee full FTR funding. PJM reduced system capability in the FTR auction model by including more outages, reducing line limits and including additional constraints. PJM's modeling changes resulted in significant reductions in Stage 1B and Stage 2 ARR allocations, a corresponding reduction in the available quantity of FTRs, a reduction in congestion revenues assigned to ARRs, and an associated surplus of congestion revenue relative to FTR target allocations. This also resulted in a significant redistribution of ARRs among ARR holders based on differences in allocations between Stage 1A and Stage 1B ARRs. Starting in the 2017/2018 planning period, with the allocation of balancing congestion and M2M payments to load rather than FTRs, PJM increased system capability allocated to Stage 1B and Stage 2 ARRs, but continued to conservatively select outages to manage FTR funding levels.

PJM has intervened aggressively in the FTR market since its inception in order to meet various subjective objectives including so called revenue adequacy. PJM should not intervene in the FTR market to subjectively manage FTR funding. PJM should fix the FTR/ARR design and then should let the market work to return congestion to load and to let FTR values reflect actual congestion.

Load should never be required to subsidize payments to FTR holders, regardless of the reason.[6] The FERC order of September 15, 2016, introduced a subsidy to FTR holders at the expense of ARR holders.[7] The order requires PJM to ignore balancing congestion when calculating total congestion dollars available to fund FTRs. As a result, balancing congestion and M2M payments are assigned to load, rather than to FTR holders, as of the 2017/2018 planning period. When combined with the direct assignment of both surplus day-ahead congestion and surplus FTR auction revenues to FTR holders, the Commission's order shifted substantial revenue from load to the holders of FTRs and further reduced the offset to congestion payments by load. This approach ignores the fact that load pays both day-ahead and balancing congestion, and that congestion is defined, in an accounting sense, to equal the sum of day-ahead and balancing congestion. Eliminating balancing congestion from the FTR revenue calculation requires load to pay twice for congestion. Load pays total congestion and pays negative balancing congestion again. The fundamental reasons that there has been a significant and persistent difference between day-ahead and balancing congestion include inadequate transmission modeling in the FTR auction and the role of UTCs in taking advantage of these modeling differences and creating negative balancing congestion. There is no reason to impose these costs on load.

These changes were made in order to increase the payout to holders of FTRs who are not loads. Increasing the payout to FTR holders at the expense of the load is not a supportable market objective. PJM should implement an FTR design that calculates and assigns congestion rights to load rather than continuing to modify the current, fundamentally flawed, design.

Load was made significantly worse off as a result of the changes made to the FTR/ARR process by PJM based on the FERC order of September 15, 2016. ARR revenues were significantly reduced for the 2017/2018 FTR Auction, the first auction under the new rules. ARRs and self scheduled FTRs offset only 49.5 percent of total congestion costs for the 2017/2018 planning period rather than the 58.0 percent offset that would have occurred under the prior rules, a difference of $101.4 million.

A subsequent rule change was implemented that modified the allocation of surplus auction revenue to load. Beginning with the 2018/2019 planning period, surplus day-ahead congestion and surplus FTR auction revenue are assigned to FTR holders only up total target allocations, and then distributed to ARR holders.[8] ARR holders will only be allocated this surplus after full funding of FTRs is accomplished. While this rule change increased the level of congestion revenues returned to load, the rules do not recognize ARR holders' rights to all congestion revenue, and only improves congestion payouts to load when there is a surplus. There was no surplus for the 2020/2021 or 2021/2022 planning years. With this rule in effect for the 2021/2022 planning period, ARRs and self scheduled FTRs offset 31.5 percent of total congestion. Load has been underpaid congestion revenues by $3.8 billion from the 2011/2012 planning period through the first ten months of the 2022/2023

6 Such subsidies have been suggested repeatedly. See FERC Dockets Nos. EL13-47-000 and EL12-19-000.
7 See 156 FERC ¶ 61,180 (2016), *reh'g denied*, 156 FERC ¶ 61,093 (2017).

8 163 FERC ¶ 61,165 (2018).

planning period. The cumulative offset for that period was 69.0 percent of total congestion.

The complex process related to what is termed the overallocation of Stage 1A ARRs is entirely an artificial result of reliance on the contract path model in the assignment of FTRs. For example, there is a reason that transmission is not built to address the Stage 1A overallocation issue. The Stage 1A overallocation issue is a fiction based on the use of outdated and irrelevant generation to load contract paths to assign Stage 1A rights that have nothing to do with actual power flows.

PJM proposed, and on March 11, 2022, FERC accepted, to increase Stage 1A ARR allocations from 50 percent of Network Service Base Load (NSBL) to 60 percent of Network Service Peak Load (NSPL) ("Stage 1A Proposal").[9] NSBL is a network service customer's contribution to the lowest daily zonal peak load in the prior twelve month period, and NSPL is a network service customer's contribution to the highest daily zonal peak load in the prior twelve month period. While PJM's proposal will increase Stage 1A rights, this will come at the cost of Stage 1B and Stage 2 ARR allocations. More importantly, PJM's proposal will not improve the alignment of congestion property rights to load, but will exacerbate the current misalignment.

Proposed Design

To address the issues with the current contract path based ARR/FTR market design, the MMU recommends that the current design be replaced with a design in which the rights to actual congestion paid are assigned directly to the load that paid that congestion by node. The assigned right would be the actual difference between load payments, both day-ahead and balancing, and revenues paid to the generation used to serve that load. The load could retain the right to the network congestion or sell the right through auctions. The correct assignment of congestion revenues to load is fully consistent with retaining FTR auctions for the sale by ARR holders of their congestion revenue rights.

9 See 178 FERC ¶ 61,170.

With a network assignment of actual congestion, there would be no cross subsidies among rights holders and no over or under allocation of rights relative to actual network market solutions. There would be no revenue shortfalls as congestion payments equal congestion collected. The risk of default would be isolated to the buyer and seller of the right, and any default would not be socialized to other right holders. In the case of a defaulting buyer, the rights to the congestion revenues would revert to the load. There would be no risk of a network right flipping in value from positive to negative, because congestion is always the positive difference between what load pays for energy, and generation is paid for energy as a result of transmission constraints.

The MMU proposal requires the calculation of constraint specific congestion and the calculation of that specific constraint's congestion related charges to each physical load bus downstream of that constraint. Under the MMU proposal, the constraint specific congestion calculated by hour, from both the day-ahead and balancing market would be paid directly to the physical load as a credit against the associated load serving entity's (LSE) energy bill. This right to the congestion is defined as the congestion revenue right (CRR) that belongs to the physical load at a defined bus, zone or aggregate. The LSE could choose to sell all or a portion of the CRR through auctions.

A CRR is the right to actual, realized network related congestion that is paid by physical load at a specific bus, zone or aggregate. Under the MMU proposal a bus, zone or aggregate specific CRR could be sold as a defined share of the actual congestion. For example, an LSE could sell 50 percent of its congestion revenue right for the planning period to a third party. The third party buyer would then be entitled to 50 percent of the congestion that will be credited to that specific bus, zone or aggregate for the planning period. The remaining 50 percent of the congestion credit for the specified bus, zone or aggregate would be paid to the LSE along with auction clearing price for the 50 percent of CRR that was sold to the third party. Depending on actual congestion, an LSE selling its congestion revenue rights could be better or worse off than if it retained its rights.

Under the MMU proposal, the LSE would be able to set reservation prices in the auction for the sale of portions or all of its CRR. Third parties would have an opportunity to bid for the offered portions of the CRR, and the market for the congestion revenue associated with the specified bus, zone or aggregate would clear at a price. If the reservation price of an identified portion of the offered CRR was not met at the clearing price, that portion of the offered CRR would remain with the load. Auctions could be annual and/or monthly.

Under the MMU proposal, point to point rights (FTRs) could exist as a separate, self-funded hedging product based on simultaneously feasible prevailing and counter flows in a PJM managed network based auction. The only supply and the only source of revenues in the point to point market for prevailing flow FTRs would be counter flow offers and direct payments for specific rights.

Auction Revenue Rights

Auction Revenue Rights (ARRs) are the mechanism used to assign congestion rights to load, using an archaic contract path based approach, and sell those rights to FTR buyers in various auctions. ARR values are based on nodal price differences established by cleared FTR bids in the Annual FTR Auction. ARR sellers have no opportunity to define a price at which they are willing to sell and must accept the prices as defined by FTR buyers. ARR revenues are a function of FTR auction participants' expectations of congestion, risk, competition and available supply. But some auction revenues may be returned to FTR buyers, despite the fact that FTR buyers willingly paid a defined price for FTRs. PJM has significant discretion over the level of supply made available to FTR buyers. The appropriate goals of that discretion should be significantly limited and defined clearly in the tariff.

ARRs are available only as obligations (not options) and only as a 24 hour product. ARRs are available to the nearest 0.1 MW. The ARR target allocation is equal to the product of the ARR MW and the price difference between the ARR sink and source from the Annual FTR Auction.[10] ARR target allocations are a set value at the time of the Annual FTR Auction. It is logically possible for ARRs to be revenue inadequate if the money collected from the FTR auction is not enough to pay the entirety of ARR target allocations for the planning period. This is extremely unlikely and can only happen if there is a modeling difference between the system model used for ARRs and the system model used for FTRs and the FTR MW are reduced. An ARR's target allocation, or value, which is established from the Annual FTR Auction, can be a benefit or liability depending on the price difference between sink and source.

The goal of the ARR/FTR design should be to provide an efficient mechanism to ensure that load receives the rights to all congestion revenues. In the current design, all auction revenues should be paid to ARR holders.

The quantity of the product made available as ARRs or for sale in the FTR auctions is defined as system capability, meaning the capacity of the transmission system to deliver power. But system capability is not congestion and system capability is not the difference in congestion prices across transmission contract paths nor the potential for such difference. The concept of system capability is not relevant to assigning the rights to congestion revenues to load. The use, or misuse, of the concept of system capability in assigning ARRs is derived entirely from the contract path approach used in the PJM design. The definition of ARRs based on contract paths led to the mistaken idea that some transmission system capacity was used by ARRs but some was not and that both the ARR capability and the excess capability was available for sale as FTRs. In the current approach, system capability available to ARR holders is limited by the system capability made available in PJM's annual FTR transmission system market model. PJM's annual FTR transmission market model represents annual, expected system capability, modified by PJM to achieve PJM's goal of guaranteeing revenue equal to target allocations for FTRs, and subject to the requirement that all Stage1A ARR requests must be allocated. Stage 1A ARR right requests are guaranteed and system capability necessary to accommodate the rights must be included in PJM's annual FTR transmission system market model.

Market Design

ARRs have been available to network service and firm, point to point transmission service customers since June 1, 2003, when the annual ARR allocation was first implemented for the 2003/2004 planning period. The initial allocation covered the Mid-Atlantic Region and the APS Control Zone.

10 These nodal prices are a function of the market participants' annual FTR bids and binding transmission constraints.

For the 2006/2007 planning period, the choice of ARRs or direct allocation FTRs was available to eligible market participants in the AEP, DAY, DUQ and DOM Control Zones. For the 2007/2008 and subsequent planning periods through the present, all eligible market participants were allocated ARRs.

Each March, PJM allocates annual ARRs to eligible customers in a three stage process: Stage 1A, Stage 1B and Stage 2B. Stage 1A ARRs are assigned based on historic contract paths and Stage 1A ARRs must be preserved for at least ten planning periods regardless of system or regulatory changes.[11]

In Stage 1A, LSEs can obtain ARRs, based on their contribution to the lowest daily zonal peak load in the prior twelve month period (NSBL) and based on generation to load contract paths that reflect generation resources that had historically served load, or their qualified replacements if the resource has retired and PJM has replaced it. The historical reference year is the year in which PJM markets were implemented, which is 1999 for the original zones, or the year in which a zone joined PJM. Firm, point to point transmission service customers can obtain Stage 1A ARRs up to 50 percent of the MW of firm, point to point transmission service provided between the receipt and delivery points for the historical reference year, subject to a cap of lowest daily peak load in the prior year. Network service customers can obtain Stage 1A ARRs based on the MW of firm service provided during the reference year, subject to a cap of lowest daily peak load in the prior year. Stage 1A ARRs cannot be prorated. If Stage 1A ARRs are found to be infeasible, transmission system upgrades must be undertaken to maintain feasibility.[12]

In Stage 1B, network transmission service customers can obtain ARRs based on their share of zonal peak load, based on generation to load contract paths, up to the difference between their share of zonal peak load and Stage 1A allocations. Firm, point to point transmission service customers can obtain ARRs based on the MW of long-term, firm, point to point service provided between the receipt and delivery points for the historical reference year.

In Stage 2, network transmission service customers can obtain ARRs from any hub, control zone, generator bus or interface pricing point to any part of their aggregate load in the control zone or load aggregation zone up to their total peak network load in that zone. Firm, point to point transmission service customers can obtain ARRs consistent with their transmission service as in Stage 1A and Stage 1B.

When ARR holders self schedule FTRs, the ARR holders choose to be paid based on variable target allocations rather than the fixed ARR value determined in the annual FTR auction. ARR holders can self schedule ARRs as FTRs during the Annual FTR Auction.[13] ARRs can be traded between LSEs prior to the first round of the Annual FTR Auction.

Effective for the 2015/2016 planning period, when residual zonal pricing was introduced, ARRs default to sinking at the load settlement point if different than the zone, but the ARR holder may elect to sink their ARR at the zone instead.[14]

In 2016, FERC ordered PJM to remove retired resources from the generation to load contract paths used to allocate Stage 1A ARRs.[15] PJM replaced retired units with operating generators, termed qualified replacement resources (QRRs).[16] Existing Stage 1A resources retain their current allocations, while ARR allocations to QRRs that replace retired Stage 1A resources are prorated based on the feasibility of these ARRs after existing resources are allocated. As a result of this proration, ARRs for QRRs have lower priority than ARRs from generators that existed in 1998.

Generation to load paths, even from active generators, are based on a contract path model rather than a network model. Generation to load contract paths should not be used as a basis for assigning the rights to congestion revenue. Contract paths are not an accurate representation of the reasons that congestion exists or of how load is served in a network and will, by definition, not accurately measure the exposure of load to congestion.

11 See "PJM Manual 6: Financial Transmission Rights," Rev. 29 (Sep. 1, 2022) at 23.
12 See "PJM Manual 6: Financial Transmission Rights," Rev 29 (Sep. 1, 2022).
13 OATT Attachment K 7.1.1.(b).
14 See "PJM Manual 6: Financial Transmission Rights," Rev. 29 (Sep. 1, 2022) at 35.
15 156 FERC ¶ 61,180 (2016).
16 See FERC Docket No. EL16-6-003.

Market Structure

ARRs are allocated on an annual basis. For the 2022/2023 planning period there were 1,563 individual participants and 133 parent companies.

The ownership of ARRs was unconcentrated, with an HHI of 584, for the 2022/2023 planning period.

Market Performance

Stage 1A Infeasibility

Stage 1A ARRs are allocated for a year, but guaranteed for 10 years, with the ability for a participant to opt out of any planning period within the 10 years. PJM conducts a simultaneous feasibility analysis to determine the transmission upgrades required to ensure that the long term ARRs can remain feasible. The rules provide that if a simultaneous feasibility test violation occurs in any year, PJM will identify or accelerate any transmission upgrades to resolve the violation and these upgrades will be recommended for inclusion in the PJM RTEP process. But such transmission upgrades must pass PJM's RTEP process.

PJM's transmission planning process (RTEP) does not identify a need for new transmission associated with Stage 1A overallocations because there is, in fact, no need for new transmission associated with Stage 1A ARRs. The Stage 1A overallocation issue is a fiction based on the use of outdated and irrelevant generation to load contract paths to assign Stage 1A rights that have nothing to do with actual power flows. This continues to be true even with the replacement of retired generating units.

For the 2019/2020 planning period, Stage 1A of the Annual ARR Allocation was infeasible, resulting in an over allocation of ARRs on the affected facilities. As a result, modeled system capability, in excess of actual system capability, was provided to the Stage 1A ARRs and added to the FTR auction. According to Section 7.4.2 (i) of the OATT, the capability limits of the binding constraints rendering these ARRs infeasible must be increased in the model and these increased limits must be used in subsequent ARR and FTR allocations and auctions for the entire planning period, except in the case of extraordinary circumstances. Stage 1A related over allocations have to be made up elsewhere in PJM's FTR market model, in the form of reduced system capability, in order for PJM to achieve its goal of fully funding FTRs.

ARR Reassignment for Retail Load Switching

PJM rules provide that when load switches between LSEs during the planning period, an LSE gaining load in the same control zone is allocated a proportional share of positively valued ARRs and residual ARRs within the control zone based on the shifted load.[17] ARRs are reassigned to the nearest 0.001 MW and may be reassigned multiple times over a planning period. The reassignment of positively valued ARRs supports competition by ensuring that the offset to congestion follows load, thereby removing a barrier to competition among LSEs and, by ensuring that only ARRs with a positive value are reassigned, preventing an LSE from assigning poor ARR choices to other LSEs. However, when ARRs are self scheduled as FTRs, the self scheduled FTRs do not follow load that shifts while the ARRs do follow load that shifts, and this may result in lower value of the ARRs for the receiving LSE compared to the total value held by the original ARR holder.

Table 13-3 summarizes ARR MW and associated revenue reassigned for network load in each control zone where changes occurred between June 2021 and March 2023.

There were 30,917 MW of ARRs associated with $1,325,600 of revenue that were reassigned in the first ten months of the 2022/2023 planning period. There were 32,935 MW of ARRs associated with $659,700 of revenue that were reassigned for the 2021/2022 planning period.

17 See "PJM Manual 6: Financial Transmission Rights," Rev. 29 (Sep. 1, 2022).

Table 13-3 ARRs and ARR revenue automatically reassigned for network load changes by control zone: June 2021 through March 2023

	ARRs Reassigned (MW-day)		ARR Revenue Reassigned [Dollars (Thousands) per MW-day]	
Control Zone	2021/2022 (12 months)	2022/2023 (10 months)	2021/2022 (12 months)	2022/2023 (10 months)
ACEC	300	270	$1.9	$1.6
AEP	4,142	3,067	$49.0	$67.2
APS	1,325	1,536	$15.5	$92.6
ATSI	3,353	6,363	$45.2	$112.3
BGE	2,393	2,213	$233.9	$289.7
COMED	3,056	1,821	$23.7	$16.6
DAY	1,074	1,118	$5.1	$8.4
DOM	120	96	$60.7	$2.7
DPL	832	772	$8.1	$56.1
DUKE	1,467	1,370	$53.0	$61.5
DUQ	1,662	1,390	$1.7	$11.8
EKPC	0	0	$0.0	$0.0
JCPLC	963	686	$2.0	$4.7
MEC	1,162	902	$9.4	$71.1
OVEC	0	0	$0.0	$0.0
PE	887	939	$14.7	$60.7
PECO	3,315	2,187	$11.5	$50.3
PEPCO	1,771	1,597	$63.3	$86.2
PPL	3,959	3,708	$16.8	$298.2
PSEG	1,116	823	$44.1	$33.7
REC	39	58	$0.1	$0.4
Total	32,935	30,917	$659.7	$1,325.6

Residual ARRs

Introduced August 1, 2012, Residual ARRs are available for eligible ARR holders when a transmission outage was modeled in the Annual ARR Allocation, but the transmission facility returns to service during the planning period. Residual ARRs can only be allocated to participants whose ARRs were prorated in Stage 1B and only to a maximum of the prorated reduction, so not all available Residual ARRs are allocated. Residual ARRs are automatically assigned to eligible participants the month before the effective date, are effective for a single month and cannot be self scheduled. Residual ARR target allocations are based on the clearing prices from FTR obligations in the relevant monthly auction, may not exceed zonal network services peak load or firm transmission reservation levels and are only available up to the prorated ARR MW capacity as allocated in the Annual ARR Allocation. For the following planning period, these Residual ARRs are available as ARRs in the annual ARR allocation. Residual ARRs are a separate product from incremental ARRs. Beginning with the June 2017 monthly auction, Residual ARRs that would have cleared with a negative target allocation are not assigned to participants.[18] In prior planning periods, PJM's modeling of excess outages in order to manage FTR market outcomes resulted in the allocation of some ARRs that would have been allocated in Stage 1B being allocated as Residual ARRs on a month to month basis without the option to self schedule.

Table 13-4 shows the Residual ARRs allocated to participants and the associated target allocations. The available volume is the total additional capacity available to be allocated as Residual ARRs. The cleared volume is the residual ARR capacity actually allocated to participants with prorated ARRs based on the level of prorated ARRs in Stage 1B and the affected paths. In the first ten months of the 2022/2023 planning period, PJM allocated a total of 27,924.0 MW of Residual ARRs with a target allocation of $31.0 million. In the same time period for the 2021/2022 planning period, PJM allocated a total of 24,023.5 MW of residual ARRs with a target allocation of $16.2 million.

Table 13-4 Residual ARR allocation volume and target allocation: 2014/2015 planning period through 2022/2023 planning period

Planning Period	Available Volume (MW)	Cleared Volume (MW)	Cleared Volume	Target Allocation
2014/2015	65,095.3	22,532.9	34.6%	$8,160,918.27
2015/2016	61,807.0	37,042.4	59.9%	$8,620,353.27
2016/2017	71,000.7	35,034.9	49.3%	$6,986,723.44
2017/2018	81,040.8	39,597.4	48.9%	$17,497,625.78
2018/2019	49,646.9	27,335.6	55.1%	$11,817,002.00
2019/2020	48,286.5	27,233.2	56.4%	$12,369,580.58
2020/2021	43,484.2	25,028.0	57.6%	$11,677,033.36
2021/2022	46,092.0	27,619.2	59.9%	$18,806,123.46
2022/2023	60,333.6	27,924.0	46.3%	$30,988,309.06

* First ten months of 2022/2023 planning period

18 See FERC Letter Order, Docket No. ER17-1057 (April 5, 2017).

IARRs

In theory, Incremental Auction Revenue Rights (IARRs) are ARRs made available by physical transmission system upgrades from customer funded transmission projects or from merchant transmission or generation interconnection requests. In order for a transmission project to result in IARRs, the project must create simultaneously feasible incremental market flow capability in PJM's ARR market model, over and above all system capability being used by existing allocated ARRs and/or would be used by granting any prorated outstanding ARR requests, in the ARR market model.[19]

There are three sources of IARRs: IARRs based on a specific transmission investment; IARRs based on merchant transmission or generation interconnection projects; and IARRs based on RTEP upgrades. In the case of a specific transmission investment, the participant elects desired IARR MW between a specified source and sink and PJM and the affected transmission owners determine the upgrades necessary to create incremental capability.[20] In the other two cases, the participants paying for the upgrades are assigned IARRs if any are created. There have been 13 successful IARR requests totaling 2,990.1 MW. One IARR path of 64.5 MW was terminated (June 1, 2012), leaving 12 unique source and sink combinations of 2,925.6 MW of IARRs. Of these 12 unique paths, three paths consisting of 1,200.0 MW were based on specific transmission investments requests, six paths consisting of 1,047.4 MW were based on merchant transmission requests and three paths consisting of 678.6 MW were based on customer funded (RTEP) transmission projects. The three paths based on specific transmission investments involved a generation company working with its affiliated transmission company. The other nine paths were based on projects that would have been built regardless of the addition of IARRs.

The MMU supports increased competition to provide transmission using market mechanisms. The IARR process is not a viable mechanism for facilitating competitive transmission investments. Maintaining the IARR process impedes the search for real solutions. PJM's process for creating and assigning IARRs is fundamentally flawed and cannot be made consistent with the requirements of Order No. 681 which established IARRs.[21]

Order No. 681 requires that long-term firm transmission rights made feasible by transmission upgrades or expansions be available upon request to the party that pays for such upgrades or expansions.[22] Order No. 681 also requires that the rights granted by upgrades/expansions cannot come at the expense of transmission rights held by others. IARRs are treated as Stage 1A rights, which are given first and absolute priority in PJM's annual allocation process. Granting Stage 1A status to IARRs is preferential treatment of IARR rights relative to the ARR rights belonging to load. If the annual market model used to assign existing ARR rights in a given year cannot simultaneously support all Stage 1A ARR requests, the system model is modified so as to make the Stage 1A ARR requests feasible. The result is an over allocation of congestion rights relative to expected congestion. To avoid having FTR target allocations exceed expected congestion, PJM reduces the annual supply (market model system capability) available to non-Stage 1A rights through selective line outages and line rating reductions. The resulting market model artificially supports all the Stage 1A ARR requests and artificially reduces the amount of remaining later tier ARRs from other rights holders. Stage 1A ARRs, including IARRs, are approved at the expense of other preexisting congestion rights. In the case of IARRs, this is in violation of Order No. 681.

The MMU recommends that IARRs be eliminated from the PJM tariff. If IARRs are not eliminated, the MMU recommends that IARRs be subject to prorating like all other ARR rights rather than being exempt from prorating.

19 See PJM Incremental Auction Revenue Rights Model Development and Analysis, PJM June 12, 2017. <https://www.pjm.com/~/media/markets-ops/ftr/pjm-iarr-model-development-and-analysis.ashx>.
20 See Attachment EE of the PJM Open Access Transmission Tariff <https://www.pjm.com/directory/merged-tariffs/oatt.pdf>.
21 See November 7, 2019 Comments on TranSource, LLC v. PJM, 168 FERC ¶ 61,119 (2019) ("Opinion No. 566").
22 *Long-Term Firm Transmission Rights in Organized Electricity Markets*, Order No. 681, 116 FERC ¶ 61,077 (2006) ("Order No. 681"), *order on reh'g*, Order No. 618-A, 117 FERC ¶ 61,201 (2006), *order on reh'g*, Order No. 681-A, 126 FERC ¶ 61,254 (2009).

Financial Transmission Rights

FTRs are financial instruments that entitle their holders to receive revenue or require them to pay charges based on locational congestion price differences in the day-ahead energy market across specific FTR transmission paths. These day-ahead congestion price differences, multiplied by the FTR position in MW, are termed the FTR target allocations. The FTR target allocations define the maximum, but not guaranteed, payout for FTRs. The target allocation of an FTR reflects the difference in day-ahead congestion prices (CLMPs) rather than the difference in LMPs, which includes both congestion and marginal losses. Negative target allocations require the FTR holder to make payments rather than receive revenues in the FTR market. One of the fundamental flaws in the FTR design is the mismatch between congestion and the differences in day-ahead prices between nodes. The difference in day-ahead congestion prices is not congestion. Target allocations are not congestion.

Under the current rules, the revenue available to pay FTR holders' target allocations in a given month includes day-ahead congestion, payments by holders of negatively valued FTRs, auction revenues greater than ARR target allocations, and any charges made to day-ahead operating reserves which occur where there are hours with net negative congestion. Any such revenue above FTR target allocations from prior months in a planning period are used to pay any current month shortfalls. Target allocations are a cap on payments to FTR holders for each planning period. At the end of each planning period, any surplus revenue above the target allocations is distributed to ARR holders.

FTR funding is not on a path specific basis or on an hour to hour basis and treats all FTRs the same. For example, if the payout ratio is less than 1.0 at the end of the planning period, the payments to all FTRs are reduced. Payments are made pro rata based on target allocations. The result is widespread cross subsidies because assignment of path specific FTRs may exceed system capability and affect the payments to FTRs on other paths. FTR auction revenues and excess revenues are carried forward from prior months and distributed back from later months within a planning period. At the end of a planning period, if some months remain not fully funded, an uplift charge is collected from any FTR market participants that hold FTRs for the planning period based on their pro rata share of total net positive FTR target allocations, excluding any charge to FTR holders with a net negative FTR position for the planning period.

Auction market participants may offer to buy FTRs between any eligible pricing nodes on the system, as defined by PJM for each auction. For the Annual FTR Auction and FTRs bought in the monthly auctions, the available FTR source and sink points include hubs, control zones, aggregates, generator buses, load buses and interface pricing points. For the Long Term FTR Auction there is a more restricted set of available hubs, control zones, aggregates, generator buses and interface pricing points available. PJM does not allow FTR buy bids to clear with a price of zero unless there is at least one constraint in the auction which affects the FTR path. FTRs are available to the nearest 0.1 MW.

FTRs are bought from supply defined by PJM. The fact that load is selling congestion revenue rights is not fully recognized in the FTR design, although FTR buyers can resell FTRs at a price they agree to accept. Load has no role in defining the price at which PJM sells FTRs on their behalf. PJM's objective in the auctions is to maximize auction revenue, given the total set of bid prices and bid MW, but absent reservation prices from load. The failure to allow sellers the ability to decide at what price to sell FTRs is a fundamental flaw in the FTR market. The result is that PJM cannot actually maximize auction revenue and that the FTR market is not really a market.

Once bought from PJM, FTRs can be bought and sold. Buy bids are bids to buy FTRs in the auctions. Sell offers are offers to sell existing FTRs in the auctions.

Market participants can buy and sell existing FTRs, outside of the auction process, through a voluntary bulletin board, termed the PJM bilateral market. FTRs can also be exchanged bilaterally without using the bulletin board. There is no requirement to report bilateral transactions, or any information about them, to PJM.

Supply and Demand

Total FTR supply in each auction is limited by the definition of the transmission system capacity included in the PJM FTR market model as modified, for example, by PJM assumptions about transmission outages, for which there are no clear rules. PJM may also limit available transmission capacity through subjective judgment exercised without any clear guidelines.

The MMU recommends that the full transmission capacity of the system be allocated as ARRs prior to sale as FTRs.

The FTR auction process does not account for the fact that significant transmission outages, which have not been provided to PJM by transmission owners prior to the auction date, will occur during the periods covered by the auctions. Such transmission outages may or may not be planned in advance or may be emergency outages.[23] In addition, it is difficult to model in an annual auction two outages of similar significance and similar duration in different areas which do not overlap in time. The choice of which to model will generally have significant distributional consequences; they will affect different areas very differently. The fact that outages are modeled at significantly lower than historical levels results in selling too much FTR capacity, which creates downward pressure on ARR prices. To address this issue, the MMU recommends that PJM use probabilistic outage modeling to better align the supply of ARRs and FTRs with actual expected transmission capacity.

Long Term FTR Auctions

In July 2006, FERC approved Order No. 681 mandating the creation of long term firm transmission rights in transmission organizations with organized electricity markets. FERC's goal was that "load serving entities be able to request and obtain transmission rights up to a reasonable amount on a long-term firm basis, instead of being limited to obtaining exclusively annual rights."[24] Despite that order and inconsistent with the directive in that order, LSEs are not able to request ARRs nor are LSEs guaranteed rights to the revenue from Long Term FTR Auctions in PJM's long term FTR auction market design. Excess system capability in years two and three of the long term FTR auction is never made available to load in the form of ARRs and is only made available to FTR buyers.

PJM conducts the Long Term FTR Auction for the next three consecutive planning periods. The Long Term FTR Auction consists of five rounds beginning in June of the preceding planning period and continuing through March. FTRs purchased in prior rounds or Long Term Auctions may be offered for sale in subsequent rounds of the long term, annual or monthly FTR auctions. FTRs obtained in the Long Term FTR Auctions have terms of one year. FTR products available in the Long Term Auction include 24 hour, on peak and off peak FTR obligations, with FTR options unavailable in the Long Term FTR Auctions.

Beginning with Round 2 of the 2019/2022 Long Term FTR Auction, PJM implemented revisions to the determination of residual system capability made available in the Long Term FTR Auctions, and eliminated the YRALL product, consistent with the MMU's recommendation. The revisions affect the determination of ARR rights reserved for ARR holders. Rather than simply preserving the ARR cleared capacity from the previous annual allocation, PJM reruns the simultaneous feasibility test for the ARR/FTR market model, without outages, using the previous year's ARR requests, prorated when necessary, and uses the resulting ARRs as the basis for reserving capability for ARR holders in the Long Term FTR Auction. The ARR requests are greater than the previously cleared ARRs. The difference between the requested ARRs and the ARR/FTR market model's transmission system capacity, both without outages, determines the residual capability offered in the Long Term FTR Auction. The revisions provide ARR holders with more congestion rights in the Long Term FTR Auction that will carry into the Annual FTR Auction.

But the revisions do not address the congestion revenue rights sold in years two and three of the Long Term FTR Auction, which remain unavailable to ARRs. Capacity awarded in the Long Term FTR Auction is unavailable as ARRs in years two and three. As a result, the rights to significant congestion revenues are still assigned to the Long Term FTR Auction without ever having been made available to ARR holders. That outcome is inconsistent with the

23 See the *2019 State of the Market Report for PJM*, Volume II, Section 12: Transmission Facility Outages: Transmission Facility Outages Analysis for the FTR Market.
24 Order No. 681 at P 17.

basic logic of ARRs and inconsistent with the stated intent of the market design which is to return all congestion revenues to load.

Long Term FTR Auction transmission capacity is determined by removing all outages and running an offline model of the previous Annual FTR Auction model with all ARR bids from the prior annual ARR allocation. Any ARR MW that clear in this offline model are reserved for ARR holders in the relevant planning periods, and are removed from the Long Term FTR Auction capability. Even this approach does not, and cannot, preserve all possible capacity for ARR holders in the first year of the Long Term Auction due to changes in system topology and outage selection between planning periods. PJM outage assumptions are a key factor in determining the supply of ARRs and the related supply of FTRs in the Annual FTR Auction.

Annual FTR Auctions

Annual FTRs are effective for an entire planning period, June 1 through May 31. Outages expected to last two or more months, as well as any outages of a shorter duration that PJM decides would cause FTR revenue inadequacy if not modeled, are included in the determination of the simultaneous feasibility for the Annual FTR Auction.[25] While the full list of outages selected is publicly posted, PJM exercises significant subjective judgment in selecting outages to accomplish FTR revenue adequacy goals and the process by which these outages are selected is not clear, is not defined and is not documented. ARR holders who wish to self schedule must inform PJM prior to round one of the annual auction. Any self scheduled ARR requests clear 25 percent of the requested volume in each round of the Annual FTR Auction as price takers. The Annual FTR Auction consists of four rounds that allow any PJM member to bid for any FTR or to offer for sale any FTR that they currently hold. FTRs in this auction can be obligations or options for peak, off peak or 24 hour periods. FTRs purchased in one round of the Annual FTR Auction can be sold in later rounds or in the Monthly Balance of Planning Period FTR Auctions.

Monthly Balance of Planning Period FTR Auctions

Total Monthly FTR Auction capacity is based on the residual capacity available after the Long Term and Annual FTR auctions are conducted and adjustments are made to outages to reflect anticipated system conditions for the time periods auctioned. Outages expected to last five or more days are included in the determination of the simultaneous feasibility test for the Monthly Balance of Planning Period FTR Auction. These are single-round monthly auctions that allow any transmission service customer or PJM member to bid for any FTR or to offer for sale any FTR that they currently hold. Beginning with the 2020/2021 planning period, market participants can bid for or offer monthly FTRs for any of the remaining individual calendar months in the planning period. FTRs in the auctions include obligations and options and 24 hour, on peak and off peak products.[26]

Bilateral Market

Market participants can buy and sell existing FTRs, outside of the auction process, through a voluntary bulletin board, termed the PJM bilateral market. FTRs can also be exchanged bilaterally without using the bulletin board. There is currently no requirement to report bilateral transactions, or any information about them, to PJM. Bilateral transactions that are not done through PJM can involve parties that are not PJM members. PJM has no knowledge of bilateral transactions, or the terms and risks of bilateral transactions, that are done outside of PJM's bilateral market system. Bilateral transactions not reported to PJM are dependent on the contract established between the parties.

For bilateral trades reported to PJM, the FTR transmission path must remain the same, FTR obligations must remain obligations, and FTR options must remain options. However, an individual FTR may be split up into multiple, smaller FTRs, down to increments of 0.1 MW. Bilateral FTRs reported to PJM can also include more restrictive start and end times, meaning that the start time cannot be earlier than the original FTR start time and the end time cannot be later than the original FTR end time. Once the bilateral transaction is reported to PJM, PJM transfers ownership and adjusts credit requirements accordingly. Participants have used bilateral trades reported to PJM to reduce their credit requirements.

There is no reason to continue to permit bilateral transactions outside the PJM market and outside the awareness of PJM. The MMU recommends that

25 See "PJM Manual 6: Financial Transmission Rights," Rev. 29 (Sep. 1, 2022).

26 See "PJM Manual 6: Financial Transmission Rights," Rev. 29 (Sep. 1, 2022).

bilateral transactions be eliminated and that all FTR transactions occur in the PJM market in order to provide full transparency consistent with the rest of the FTR market and to ensure no credit issues are missed.

Market Structure

In order to evaluate the ownership of FTRs, the MMU categorizes all participants owning FTRs in PJM as either physical or financial. Physical entities include utilities and customers which primarily take physical positions in PJM markets. Financial entities include banks, trading firms and hedge funds which primarily take financial positions in PJM markets. International market participants that primarily take financial positions in PJM markets are generally considered to be financial entities even if they are utilities in their own countries.

Table 13-5 presents the monthly balance of planning period FTR auction cleared FTRs in the first three months of 2023 by trade type, organization type and FTR direction. Financial entities purchased 83.1 percent of prevailing flow FTRs, down 0.2 percentage points, and 92.4 percent of counter flow FTRs, up 1.9 percentage points, from the same period in 2022, with the result that financial entities purchased 87.7 percent, up 0.6 percentage points, of all prevailing and counter flow FTR buy bids in the monthly balance of planning period FTR auction for the first three months of 2023.

Table 13-5 Monthly Balance of Planning Period FTR Auction patterns of ownership by FTR direction: January through March, 2023

		FTR Direction		
Trade Type	Organization Type	Prevailing Flow	Counter Flow	All
Buy Bids	Physical	16.9%	7.6%	12.3%
	Financial	83.1%	92.4%	87.7%
	Total	100.0%	100.0%	100.0%
Sell	Physical	15.7%	10.3%	14.3%
	Financial	84.3%	89.7%	85.7%
	Total	100.0%	100.0%	100.0%

Table 13-6 shows the monthly cumulative HHI values for cleared obligation MW for the first ten months of the 2022/2023 planning period monthly auctions for prevailing flow FTRs. Ownership of cleared prevailing flow bids was unconcentrated in 93.3 percent of periods and moderately concentrated in 6.7 percent of periods.[27]

Table 13-6 Monthly Balance of Planning Period FTR Auction HHIs by period for prevailing flow FTRs

	Auction Period											
Auction	JUN	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY
Jun-22	468	588	582	1119	1216	848	692	704	621	802	694	793
Jul-22		418	519	886	1059	733	758	773	717	761	719	749
Aug-22			439	900	1074	776	824	760	750	747	713	769
Sep-22				737	1124	855	973	887	887	817	726	828
Oct-22					589	653	755	707	696	690	642	708
Nov-22						460	652	641	622	640	610	679
Dec-22							465	589	556	601	587	642
Jan-23								451	505	578	565	609
Feb-23									444	576	569	606
Mar-23										530	546	595

Table 13-7 shows the monthly cumulative HHI values for cleared obligation MW for the first ten months of the 2022/2023 planning period monthly auctions by month for counter flow FTRs. Ownership of cleared counter flow bids was unconcentrated in 66.7 percent of periods and moderately concentrated in 33.3 percent of periods.

Table 13-7 Monthly Balance of Planning Period FTR Auction HHIs by period for counter flow FTRs

	Auction Period											
Auction	JUN	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY
Jun-22	776	735	788	930	1329	1194	1134	1383	1396	1358	945	973
Jul-22		576	614	822	1190	1092	984	1089	1113	1150	1014	973
Aug-22			573	844	1058	1017	935	1052	1085	1088	1020	961
Sep-22				744	1007	964	923	1079	1081	1150	1083	1021
Oct-22					709	780	809	889	899	1030	989	914
Nov-22						651	751	833	856	955	946	879
Dec-22							632	773	808	892	901	846
Jan-23								679	776	836	841	805
Feb-23									698	816	834	808
Mar-23										734	790	794

27 See *2022 State of the Market Report for PJM*, Section 3: Energy Market, Competitive Assessment for HHI definitions.

Table 13-8 shows the average daily FTR ownership for all FTRs for the first three months of 2023 by organization type, by FTR direction and self scheduled FTRs.

Table 13-8 Daily FTR held position ownership by FTR direction: January through March, 2023

	FTR Direction		
Organization Type	Prevailing Flow	Counter Flow	All
Physical	26.6%	12.8%	20.0%
Physical Self Scheduled	9.1%	0.2%	4.8%
Financial	64.3%	87.1%	75.2%
Total	100.0%	100.0%	100.0%

Market Performance

Volume

PJM regularly intervenes in the FTR market based on subjective judgment which is not based on clear or documented guidelines. Such intervention in the FTR, or any market, is not appropriate and not consistent with the operation of competitive markets. In an apparent effort to manage FTR revenues, PJM may adjust normal transmission limits in the FTR auction model. If, in PJM's judgment, the normal transmission limit is not consistent with revenue adequacy goals and simultaneous feasibility, then transmission limits are reduced pro rata based on the MW of Stage 1A infeasibility and the availability of auction bids for counter flow FTRs.[28] PJM may also remove or reduce infeasibilities caused by transmission outages by clearing counter flow bids without being required to clear the corresponding prevailing flow bids.[29] The use of both of these procedures is contingent on the conditions that: PJM actions not affect the revenue adequacy of allocated ARRs; all requested self scheduled FTRs clear; and net FTR auction revenue is positive.

28 See "PJM Manual 6: Financial Transmission Rights," Rev. 29 (Sep. 1, 2022).
29 See *id.*

Monthly Balance of Planning Period Auctions

Table 13-9 provides the monthly balance of planning period FTR auction market volume for the entire 2021/2022 and the first ten months of the 2022/2023 planning periods. There were 33,137,007 MW of FTR obligation buy bids and 18,447,185 MW of FTR obligation sell offers for all bidding periods in the first ten months of the 2022/2023 planning period.[30] The monthly balance of planning period FTR auction cleared 6,270,131 (18.9 percent) of FTR obligation buy bids and 2,648,623 MW (14.4 percent) of FTR obligation sell offers.

There were 4,606,878 MW of FTR option buy bids and 2,368,120 MW of FTR option sell offers for all bidding periods in the Monthly Balance of Planning Period FTR Auctions for the first ten months of the 2022/2023 planning period. The ownership of options was highly concentrated in all periods. The monthly auctions cleared 402,008 MW (8.7 percent) of FTR option buy bids and 583,040 MW (24.6 percent) of FTR option sell offers.

30 The term obligation is used only to distinguish FTRs from options.

Table 13-9 Monthly Balance of Planning Period FTR Auction market volume: January through March, 2023

Monthly Auction	Type	Trade Type	Bid and Requested Count	Bid and Requested Volume (MW)	Cleared Volume (MW)	Cleared Volume	Uncleared Volume (MW)	Uncleared Volume
Jan-23	Obligations	Buy bids	536,658	3,138,537	680,128	21.7%	2,458,409	78.3%
		Sell offers	415,677	1,765,747	215,764	12.2%	1,549,983	87.8%
	Options	Buy bids	42,295	636,018	27,089	4.3%	608,929	95.7%
		Sell offers	73,490	236,679	67,564	28.5%	169,114	71.5%
Feb-23	Obligations	Buy bids	476,166	2,880,060	556,526	19.3%	2,323,534	80.7%
		Sell offers	356,661	1,426,578	193,042	13.5%	1,233,536	86.5%
	Options	Buy bids	31,042	437,064	26,769	6.1%	410,295	93.9%
		Sell offers	61,261	200,193	46,901	23.4%	153,292	76.6%
Mar-23	Obligations	Buy bids	413,451	2,875,283	525,283	18.3%	2,350,000	81.7%
		Sell offers	290,146	1,099,154	199,044	18.1%	900,110	81.9%
	Options	Buy bids	19,851	347,670	30,070	8.6%	317,600	91.4%
		Sell offers	44,154	168,816	43,617	25.8%	125,199	74.2%
2021/2022*	Obligations	Buy bids	5,524,001	24,606,901	5,426,331	22.1%	19,180,571	77.9%
		Sell offers	3,662,125	13,289,542	2,601,701	19.6%	10,687,841	80.4%
	Options	Buy bids	172,879	4,370,065	259,467	5.9%	4,110,598	94.1%
		Sell offers	364,911	2,313,988	551,119	23.8%	1,762,869	76.2%
2022/2023**	Obligations	Buy bids	5,896,363	33,137,007	6,270,131	18.9%	26,866,877	81.1%
		Sell offers	4,616,888	18,447,185	2,648,623	14.4%	15,798,561	85.6%
	Options	Buy bids	392,238	4,606,878	402,008	8.7%	4,204,870	91.3%
		Sell offers	778,775	2,368,120	583,040	24.6%	1,785,080	75.4%

* Shows 12 months for 2021/2022 ** Shows 10 months for 2022/2023

Figure 13-1 shows the bid volume from each monthly auction for each period of the Monthly Balance of Planning Period FTR Auction. The prompt month is the final month for which FTRs for a specific month are sold. For example, June is the prompt month for June FTRs sold in the June auction, which occurs in May. The bid volume for the non-prompt months is significantly lower than for the prompt months. On average, the non-prompt month bid volume is 44.5 percent of the prompt month bid volume.

Figure 13-1 Monthly Balance of Planning Period FTR Auction bid volume (MW per period): June 2022 through March 2023 Auction

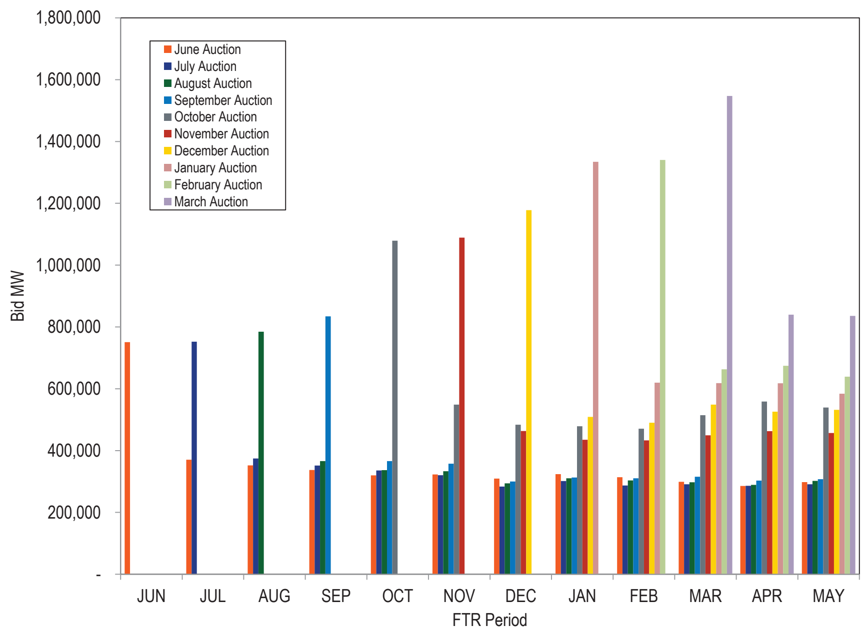


Figure 13-2 shows the cleared volume from each monthly auction for each period of the Monthly Balance of Planning Period FTR Auction. The cleared volume for non-prompt months is also significantly lower than in prompt months. On average, the non-prompt months cleared volume is 26.4 percent of the prompt month cleared volume.

Figure 13-2 Monthly Balance of Planning Period FTR Auction cleared volume (MW per period): June 2022 through March 2023 Auction

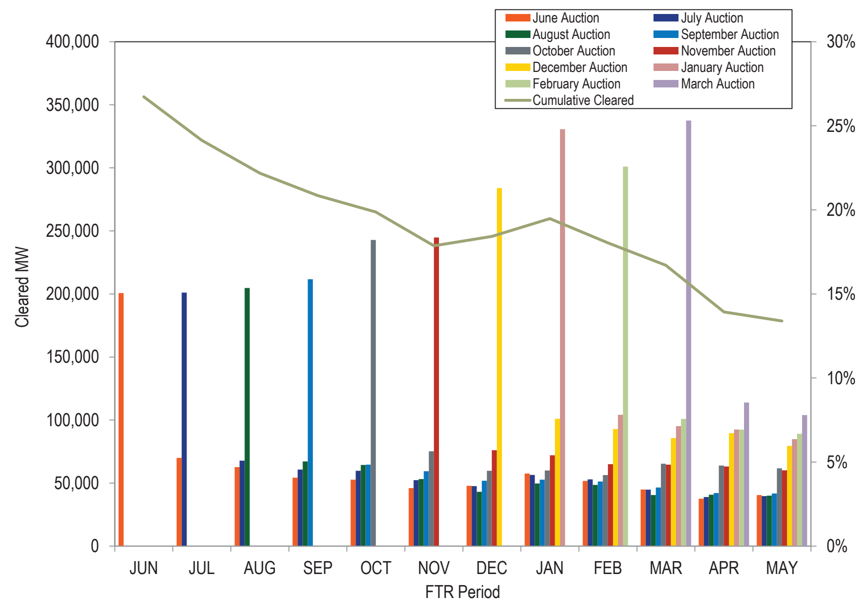


Figure 13-3 shows the FTR bid, net bid and cleared volume from June 2003 through March 2023 for Long Term, Annual and Monthly Balance of Planning Period Auctions. Cleared volume includes FTR buy and sell offers that were accepted. The net bid volume includes the total buy, sell and self scheduled offers, counting sell offers as a negative volume. The bid volume is the total of all bid and self scheduled offers, excluding sell offers. The cleared volume in August 2018 was negative due to the liquidation of the GreenHat FTR portfolio, which resulted in a large quantity of FTRs selling in the monthly auction.

Figure 13-3 Long Term, Annual and Monthly FTR Auction bid and cleared volume: June 2003 through March 2023

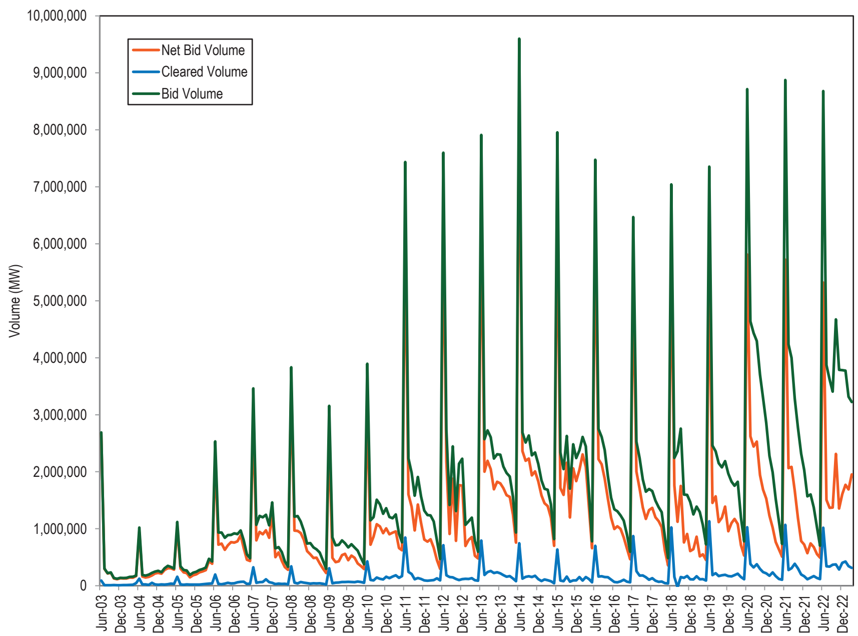
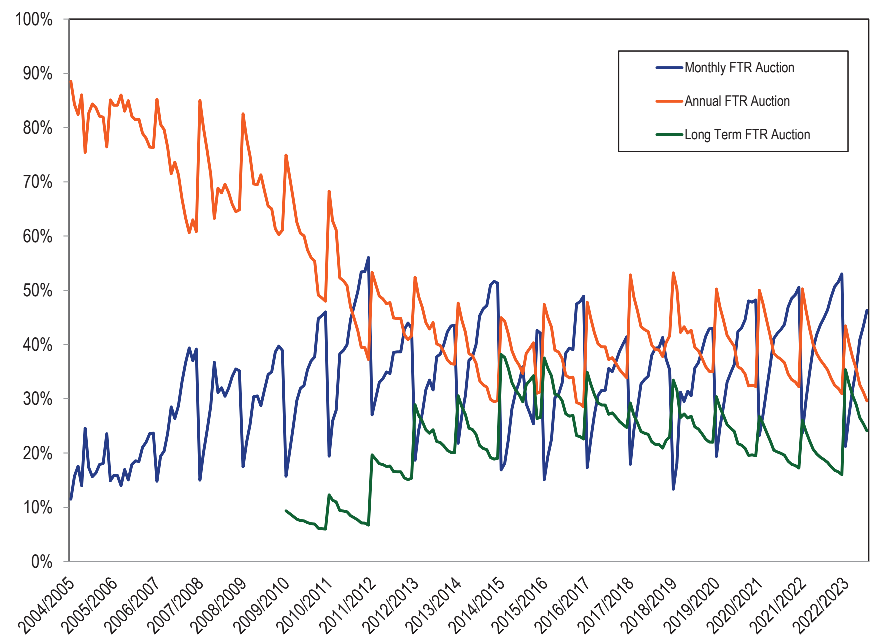


Figure 13-4 shows cleared auction volumes by auction type as a percent of the total FTR cleared volume by calendar months for June 2004 through March 2023. FTR volumes are included in the calendar month they are effective, with long term and annual FTR auction volumes spread equally to each month in the relevant planning period. Over the course of each planning period an increasing number of Monthly Balance of Planning Period FTRs are purchased, resulting in a greater share of total FTRs. When the Annual FTR Auction occurs, FTRs purchased in previous Monthly Balance of Planning Period Auctions, other than the current June auction, are no longer effective, resulting in a smaller share for monthly and a greater share for annual FTRs.

Figure 13-4 Cleared auction volume (MW) as a percent of total FTR cleared volume by calendar month: June 2004 through March 2023



Bilateral Market

Table 13-10 provides the PJM registered secondary bilateral FTR market volume for the 2021/2022 and the first ten months of the 2022/2023 planning periods. Bilateral FTR transactions registered through PJM do not need to include an accurate price or the entire volume of the transaction. Bilateral FTR transactions are not required to be registered through PJM. As a result, the bilateral data are not a reliable basis for evaluating actual bilateral activity in PJM FTRs.

Table 13-10 Secondary bilateral FTR market volume: 2021/2022 and 2022/2023[31]

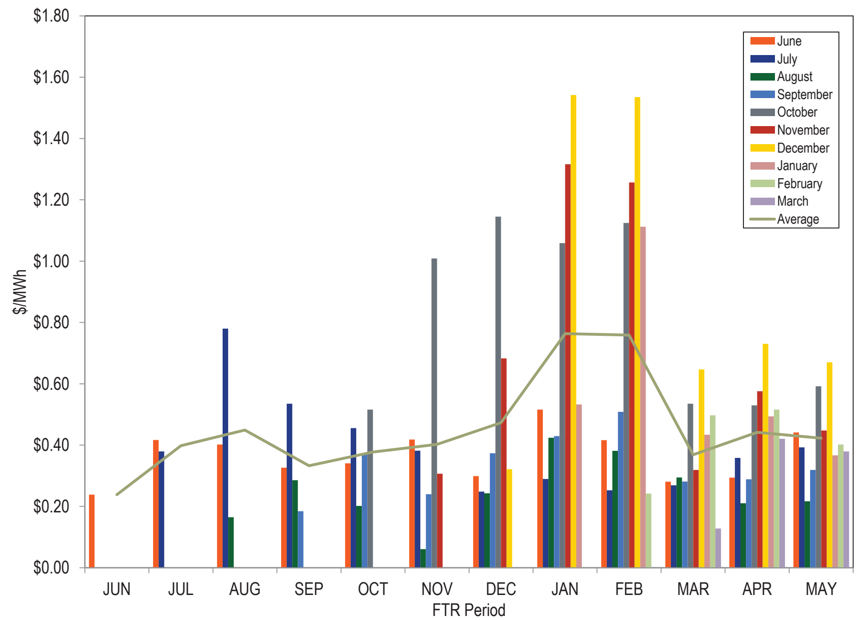
Planning Period	Type	Class Type	Volume (MW)
2021/2022	Obligation	24-Hour	6,275.4
		On Peak	99,564.8
		Off Peak	69,557.3
		Total	175,397.5
	Option	24-Hour	0.0
		On Peak	16,009.0
		Off Peak	20,846.6
		Total	36,855.6
2022/2023*	Obligation	24-Hour	537.6
		On Peak	106.6
		Off Peak	184.4
		Total	828.6
	Option	24-Hour	50.0
		On Peak	0.0
		Off Peak	0.0
		Total	50.0

* First ten months of 2022/2023 planning period

Price

Figure 13-5 shows the weighted average cleared buy bid price of obligations in the Monthly Balance of Planning Period FTR Auctions by bidding period for the first ten months of the 2022/2023 planning period and the average price per MWh for each of the FTR periods.

Figure 13-5 Monthly Balance of Planning Period FTR Auction cleared weighted-average buy bid price per period (Dollars per MWh): 2022/2023 planning period



Profitability

FTR profitability is the difference between the revenue received directly from holding an FTR plus any revenue from the sale of an FTR, and the cost of the FTR. FTR profitability is relevant only to participants purchasing FTRs and is not relevant to self scheduled FTRs. For a prevailing flow FTR, the FTR revenue is the actual revenue that an FTR holder is paid as the target allocation plus the auction price from the sale of the FTR, if relevant, and the FTR cost is the auction price. For a counter flow FTR, the FTR revenue is the auction price that an FTR holder is paid to take the FTR plus the positive auction price from the sale of the FTR, if relevant, and the FTR cost is the target allocation that the FTR holder must pay plus the negative auction price from the sale of the FTR, if relevant. Profits include the payment of surplus to

31 The 2021/2022 planning period covers bilateral FTRs that are effective for any time between June 1, 2021 through May 31, 2022, which originally had been purchased in a Long Term FTR Auction, Annual FTR Auction or Monthly Balance of Planning Period FTR Auction.

FTRs. Bilateral transactions are excluded from the profit calculations because there are inconsistent reporting requirements and no assurance that reported prices reflect the actual prices under the PJM rules. Bilateral profits and losses net to zero in market total profits and losses. ARR holders that self schedule FTRs receive congestion revenues but do not receive profits from those FTRs because ARR holders are assigned the rights to congestion revenues which they choose to take directly as the congestion payments associated with the corresponding FTRs.

Profits in the first 10 months of the 2022/2023 planning period include the auction cost and revenue from both buying and selling FTRs that were effective between June 2022 and March 2023. This includes FTRs from the 2020/2023, 2021/2024 and 2022/2025 Long Term auctions, the 2022/2023 Annual auction, and the Monthly auctions from June 2022 through March 2023. The costs and revenues of the yearly FTR products are prorated based on the period of the FTRs. Any revenues or costs related to bilateral transactions are not included in profits.

Hourly FTR profits are the sum of the hourly revenues minus the hourly costs for each FTR. The hourly revenues equal any positive hourly FTR target allocations, adjusted by the payout ratio plus any hourly auction revenues from the sale and/or the purchase of the FTR. The hourly auction costs equal any negative hourly FTR target allocations plus any hourly auction costs from the purchase and/or the sale of the FTR. The hourly auction costs and auction revenues are the product of the FTR MW and the auction price divided by the period of the FTR in hours. The FTR revenues do not include after the fact adjustments which are very small and do not occur in every month.

The surplus includes surplus day-ahead congestion revenue and FTR auction surplus. The surplus is first allocated to FTR holders to cover any shortfall in paying FTR target allocations for the current month or prior months in the planning period. A negative surplus (shortfall) at the end of the planning period is a deficiency that is charged as FTR uplift to FTR holders. The end of planning period surplus or uplift was distributed to FTR holders prorata based on FTR positive target allocations through the 2017/2018 planning period. Beginning with the 2018/2019 planning period, after covering any shortfall in FTR target allocations within the planning period, the net surplus at the end of the planning period is distributed to ARR holders. Profits include any surplus distribution or uplift payments that was used to satisfy any shortfall in FTR target allocations.

The fact that FTR profits in each planning period have been positive for financial entities as a group, regardless of the payout ratio, raises questions about the competitiveness of the market. FTR profits for financial entities were not positive in the 2019/2020 planning period when accounting for GreenHat losses but were positive otherwise. FTR profits for financial entities without GreenHat losses were positive in every planning period from 2012/2013 through 2022/2023 except the 2016/2017 planning period, and were positive if summed over the entire period. Financial entities have been much more profitable than physical and physical ARR entities combined except for the 2015/2016 and the 2016/2017 planning periods (Table 13-13). It is not clear, in a competitive market, why FTR profits for financial entities remain persistently profitable and much more profitable than other participants. In a competitive market, it would be expected that profits would be competed to zero.

Table 13-11 lists FTR profits, and the congestion returned through self scheduled FTRs, by organization type and FTR direction for the first 10 months of the 2022/2023 planning period. All participants who were assigned ARRs are classified as physical ARR. Some participants that are not eligible for ARRs are classified as physical because they are physical participants, for example companies that own only generation.

In the first 10 months of the 2022/2023 planning period, physical entities, including physical and physical ARR participants, received $23.5 million in profits on FTRs purchased directly (not self scheduled), down from $201.3 million in profits in the same time period in the 2021/2022 planning period. Financial participants received $369.6 million in profits, down from $598.4 million in profits in the same time period in the 2021/2022 planning period. Self scheduled FTRs have zero cost. ARR holders who self scheduled FTRs received $572.8 million in congestion revenues, up from $314.8 million in revenue in the same time period in the 2021/2022 planning period. Revenues from self scheduled FTRs are a return of congestion to the load that paid the congestion and are not profits.

Table 13-11 FTR profits and revenues by organization type and FTR direction: 2022/2023: June through March

	Purchased FTRs Profit			Self Scheduled FTRs Revenue Returned		
Organization Type	Prevailing Flow	Counter Flow	Total	Prevailing Flow	Counter Flow	Total
Financial	$316,522,203	$53,052,488	$369,574,692			
Physical	($1,058,136)	$22,442,851	$21,384,715			
Physical ARR	$37,387,557	($35,267,691)	$2,119,866	$564,702,132	$8,065,962	$572,768,094
Total	$352,851,624	$40,227,649	$393,079,273	$564,702,132	$8,065,962	$572,768,094

Table 13-12 lists the monthly FTR profits for the 2021/2022 planning period and the 2022/2023 planning period by organization type. In the first 10 months of the 2022/2023 planning period, profits for all participants were $393.1 million, down from $799.7 million in profits for the same time period in the 2021/2022 planning period. The largest month to month decrease in profits was in January, $290.5 million, while March was the least profitable month with losses of $63.2 million. Among organization types, financial organizations had the largest decrease in profits, $249.7 million, or 40 percent, while physical organizations' profits decreased by $157.3 million, or 88 percent, and physical ARR organizations' profits decreased by $34.3 million, or 94 percent.

Table 13-12 Monthly FTR profits by organization type: 2021/2022 and 2022/2023

	Organization Type			
Month	Financial	Physical	Physical ARR	Total
Jun-21	$22,749,776	$10,606,339	($1,804,140)	$31,551,975
Jul-21	$8,954,231	$1,444,400	($2,291,232)	$8,107,399
Aug-21	$46,644,100	$6,599,865	($1,540,329)	$51,703,636
Sep-21	$34,557,289	$16,956,350	$1,899,307	$53,412,946
Oct-21	$31,270,038	$25,268,849	$11,751,068	$68,289,955
Nov-21	$116,821,607	$43,470,687	$24,301,446	$184,593,740
Dec-21	$51,669,759	$17,990,752	$5,025,774	$74,686,286
Jan-22	$194,692,701	$48,237,853	($736,180)	$242,194,374
Feb-22	$78,598,638	$3,939,750	$2,163,530	$84,701,917
Mar-22	$33,362,979	$4,158,572	($2,300,900)	$35,220,651
Apr-22	$69,598,243	$14,635,329	($1,740,487)	$82,493,085
May-22	$142,570,155	$34,980,452	$435,586	$177,986,193
Summary for Planning Period 2021/2022				
Total	$831,489,515	$228,289,196	$35,163,444	$1,094,942,155
Jun-22	$38,826,556	$32,051,827	$16,902,773	$87,781,157
Jul-22	$51,488,899	$5,584,937	($3,493,815)	$53,580,021
Aug-22	$85,347,316	$13,777,652	($4,086,437)	$95,038,531
Sep-22	$49,416,734	$21,771,486	$10,677,196	$81,865,416
Oct-22	$41,442,598	$6,066,363	$9,625,878	$57,134,840
Nov-22	$47,290,615	$8,598,279	$1,713,849	$57,602,743
Dec-22	$99,381,028	$7,281,468	$1,000,116	$107,662,612
Jan-23	($14,285,912)	($29,361,875)	($4,651,677)	($48,299,464)
Feb-23	$2,807,556	($29,424,384)	($9,499,237)	($36,116,066)
Mar-23	($32,140,699)	($14,961,039)	($16,068,780)	($63,170,517)
Summary for Planning Period 2022/2023				
Total	$369,574,692	$21,384,715	$2,119,866	$393,079,273

Table 13-13 lists the historical profits by planning period by organization type beginning in the 2012/2013 planning period for purchased FTRs. (Profits do not include congestion revenue to self scheduled FTRs.) End of year surplus is allocated to ARR holders and end of year shortfalls are allocated to FTR holders as uplift. There was a $112.3 million end of year surplus in the 2018/2019 planning period; a $140.7 million end of year surplus in the 2019/2020 planning period; a $14.5 million end of year shortfall in the 2020/2021 planning period; and a $29.5 million end of year shortfall in the 2021/2022 planning period.

Table 13-13 FTR profits by organization type: 2012/2013 through 2022/2023

		2012/2013	2013/2014	2014/2015	2015/2016	2016/2017	2017/2018	2018/2019	2019/2020	2020/2021	2021/2022	2022/2023
Financial	Profit	$201,825,234	$913,502,323	$250,551,943	$68,895,867	($12,525,947)	$239,981,474	$113,086,231	($21,139,644)	$280,586,579	$831,489,515	$369,574,692
	Surplus	($50,304,408)	($145,080,521)	$19,453,837	$4,921,078	$8,810,267	$90,361,918					
	Total	$151,520,826	$768,421,802	$270,005,781	$73,816,945	($3,715,680)	$330,343,392	$113,086,231	($21,139,644)	$280,586,579	$831,489,515	$369,574,692
Financial without GreenHat	Profit	$201,825,234	$913,502,323	$250,551,785	$70,094,918	($11,821,248)	$240,111,850	$223,376,757	$25,150,852	$280,906,014	$831,489,515	$369,574,692
	Surplus	($50,304,408)	($145,080,521)	$19,453,837	$4,921,078	$8,810,267	$90,361,918					
	Total	$151,520,826	$768,421,802	$270,005,623	$75,015,995	($3,010,981)	$330,473,768	$223,376,757	$25,150,852	$280,906,014	$831,489,515	$369,574,692
Physical	Profit	$68,537,800	$297,456,284	$82,853,390	$10,007,327	($4,010,669)	$57,532,872	($5,945,233)	($42,860,656)	$60,941,495	$228,289,196	$21,384,715
	Surplus	($41,626,011)	($53,642,077)	$5,395,706	$1,865,146	$4,181,855	$34,296,618					
	Total	$26,911,789	$243,814,207	$88,249,096	$11,872,473	$171,186	$91,829,490	($5,945,233)	($42,860,656)	$60,941,495	$228,289,196	$21,384,715
Physical ARR	Profit	$26,572,818	$366,128,947	$112,609,140	$82,181,795	($2,468,152)	$66,458,939	($6,248,557)	($49,614,191)	$18,982,052	$35,163,444	$2,119,866
	Surplus	($25,873,836)	($81,279,067)	$18,515,990	$7,110,576	$12,040,688	$47,753,635					
	Surplus from Self scheduled FTRs	($45,978,766)	($81,765,964)	$15,530,158	$3,073,711	$6,469,297	$42,513,186					
	Total	$698,982	$284,849,881	$131,125,130	$89,292,371	$9,572,536	$114,212,574	($6,248,557)	($49,614,191)	$18,982,052	$35,163,444	$2,119,866
Total		$179,131,597	$1,297,085,890	$489,380,007	$174,981,788	$6,028,043	$536,385,456	$100,892,442	($113,614,490)	$360,510,126	$1,094,942,155	$393,079,273

* The first 10 months of the 2022/2023 planning period

Table 13-14 shows the profits and losses of the five most and the five least profitable participants by patterns of ownership. Total MWh is the sum of all MWh by ownership type regardless of profitability. The Top 5 Profit is the sum of the profits of the five most profitable participants by ownership type. The Top 5 Profit/MWh is the Top 5 Profit divided by the sum of the MWh of the top 5 participants by ownership type. The Top 5 Market Share of MWh is the sum of the MWh of the top 5 participants by ownership type divided by Total MWh. The Top 5 Profit Share Among Profitable Participants is the Top 5 Profit divided by the sum of the profits of all profitable participants by ownership type. The same logic applies for the statistics related to the Bottom 5 participants. The All row considers all ownership types when selecting the Top 5 and Bottom 5 participants.

When all participants across ownership types are considered, four of the Top 5 participants and two of the Bottom 5 participants were financial participants. Of all the ownership types, the Top 5 physical ARR participants' share of profits was the highest, 94.6 percent, although the total profits of that group were the lowest. There are only a small number of physical ARR participants who directly purchase FTRs. Overall, the five most profitable participants' profits and profit per MWh decreased and the five least profitable participants' losses and loss per MWh increased in the first 10 months of the 2022/2023 planning period compared with the same period in the 2021/2022 planning period. Each organization type's top 5 participants' profits sum and average profit per MWh decreased. The Top 5 financial participants' profits had the largest decrease compared with the same period in the 2021/2022 planning period while their profit per MWh had the smallest decrease. The Top 5 physical participants had the largest profit per MWh decrease. Each organization type's bottom 5 participants' losses sum and average loss per MWh increased. The Bottom 5 financial participants' losses and loss per MWh had the largest change. Financial participants were the only organization type that had an increase in the bottom 5 loss share. There was one financial participant who had big losses in January and in February and whose monthly losses were similar to or greater than the market total losses. There are participants who have had persistent losses for multiple years. It is possible for PJM FTR participants to have complementary positions in other trading platforms such as the Intercontinental Exchange (ICE) or Nodal Exchange.

Table 13-14 Top 5 and bottom 5 FTR profits by ownership type: 2022/2023: June through March

Organization Type	Total MWh	Top 5 Profit	Top 5 Profit/MWh	Top 5 Market Share in MWh	Top 5 Profit Share Among Profitable Participants	Bottom 5 Loss	Bottom 5 Loss/MWh	Bottom 5 Market Share in MWh	Bottom 5 Loss Share Among Unprofitable Participants
Financial	2,918,980,481	$203,964,075	$0.38	18.6%	38.4%	($138,310,391)	($0.70)	6.7%	85.4%
Physical	454,724,382	$82,865,870	$0.58	31.4%	61.0%	($76,074,005)	($1.11)	15.1%	66.4%
Physical ARR	320,835,097	$56,997,463	$0.31	58.2%	94.6%	($36,775,602)	($0.43)	26.9%	63.3%
All	3,694,539,961	$221,579,637	$0.35	17.1%	30.4%	($174,118,529)	($0.95)	5.0%	52.0%

Table 13-15 shows the shares of the number of profitable and unprofitable participants by ownership type weighted by FTR MWh in the first 10 months of the 2022/2023 planning period. All ownership types had more profitable participants than unprofitable participants. Compared to the same period in the 2021/2022 planning period, the share of the profitable participants increased from 75.4 percent to 80.8 percent. The share of the profitable participants increased for financial and physical ARR organization types. In the first 10 months of the 2022/2023 planning period, there are fewer unprofitable participants but the sum of all the losses are greater than four times of the sum of the losses in the same period in the 2021/2022 planning period. In other words, losses were more concentrated in the first 10 months in the 2022/2023 planning period than in the same period in the 2021/2022 planning period.

Table 13-15 Share of participants by profitability by ownership type: 2022/2023: June through March

Organization Type	Unprofitable	Profitable
Financial	13.9%	86.1%
Physical	41.0%	59.0%
Physical ARR	36.8%	63.2%
Total	19.2%	80.8%

Table 13-16 shows the profits by source and sink node type in the first 10 months of the 2022/2023 planning period. The sink total row is the sum of all profits and losses of FTRs that have the same sink node type. The source total column is the sum of all profits and losses of FTRs that have the same source node type. The profits of generator to generator FTRs were the largest, $213.6 million, 54.3 percent of the total profits. The losses of hub to zone FTRs were the largest, -$63.5 million. The profits of hub to hub FTRs decreased the most, $126.4 million, compared with the same period in the 2021/2022 planning period.

Table 13-16 Profits by node type matrix: 2022/2023: June through March

	Sink Type								
Source Type	Aggregate	EHVAGG	Generator	Hub	Interface	Load	Residual Metered Aggregate	Zone	Source Total
Aggregate	$7,126,180	$445,194	$41,311,085	$279,505	$2,778,569	($181,677)	$2,426,136	$4,928,233	$59,113,225
EHVAGG	$17,415	$4,401	$163,553	($28,055)	$9,567	($755,890)	($21,596)	$160,558	($450,046)
Generator	$53,975,117	$2,508,176	$213,613,791	($4,232,691)	$19,340,181	$10,468,643	$20,264,391	$5,403,692	$321,341,299
Hub	($9,005,545)	$11,522	($4,758,433)	($19,062,878)	($5,216,037)	($98,344)	$2,705,169	($63,460,852)	($98,885,399)
Interface	($21,600)	$523	$950,886	($103,434)	($280,347)	$74,337	$307,505	$1,242,916	$2,170,786
Load	$1,483,634	$2,129,920	($1,829,249)	($334,234)	$361,962	$47,211,661	($5,175)	($1,172,787)	$47,845,733
Residual Metered Aggregate	($158,424)	$26,987	($6,187,250)	$245,072	($172,688)	$4,713	$118,075	($210,609)	($6,334,126)
Zone	($139,450)	$765	($14,470,191)	$67,505,790	($5,888,525)	$959,827	$2,315,840	$17,993,744	$68,277,801
Sink Total	$53,277,328	$5,127,487	$228,794,192	$44,269,076	$10,932,683	$57,683,269	$28,110,344	($35,115,105)	$393,079,273

Table 13-17 shows the profit per MWh by source and sink node type in the first 10 months of the 2022/2023 planning period. The sink total row represents the average profit per MWh of FTRs that have the same sink type. The source total column shows the average profit per MWh of FTRs that have the same source type. Aggregate to EHV aggregate FTRs had the highest profit per MWh, $1.39 per MWh. Interface to interface FTRs had the largest loss per MWh, -$1.99 per MWh. Profit per MWh of generator to generator FTRs was $0.13 per MWh which is greater than market average, $0.11 per MWh.

Table 13-17 Profit per MWh by node type matrix: 2022/2023: June through March

	Sink Type								
Source Type	Aggregate	EHVAGG	Generator	Hub	Interface	Load	Residual Metered Aggregate	Zone	Source Total
Aggregate	$0.21	$1.39	$0.26	$0.07	$0.76	($0.04)	$0.16	$0.36	$0.25
EHVAGG	$0.05	$0.00	$0.07	($0.56)	$0.54	($0.09)	($0.25)	$1.30	($0.03)
Generator	$0.23	$0.77	$0.13	($0.04)	$0.75	$0.16	$0.51	$0.02	$0.14
Hub	($0.88)	$0.39	($0.32)	($0.29)	($1.20)	($0.46)	$0.06	($0.38)	($0.32)
Interface	($0.02)	$0.11	$0.16	($0.10)	($1.99)	$0.44	$0.63	$0.73	$0.20
Load	$0.28	$0.60	($0.03)	($0.93)	$0.93	$0.12	($0.00)	($1.43)	$0.11
Residual Metered Aggregate	($0.06)	$0.95	($0.24)	$0.39	($1.51)	$0.00	$0.10	($0.13)	($0.19)
Zone	($0.01)	$0.11	($0.38)	$1.05	($0.98)	$1.32	$0.05	$0.17	$0.25
Sink Total	$0.18	$0.51	$0.12	$0.18	$0.27	$0.12	$0.19	($0.07)	$0.11

Revenue

Monthly Balance of Planning Period FTR Auction Revenue

Table 13-18 shows monthly balance of planning period FTR auction revenue by trade type, type and class type for the first three months of 2023. Beginning with the October 2022 Auction, Daily Off Peak and Weekend On Peak class types were introduced to replace the Off Peak Class type. The Monthly Balance of Planning Period FTR Auctions for the first ten months of the 2022/2023 planning period netted $102.2 million in revenue, the difference between buyers paying $693.6 million and sellers receiving $591.4 million. For the entire 2021/2022 planning period, the Monthly Balance of Planning Period FTR Auctions netted $50.3 million in revenue with buyers paying $412.5 million and sellers receiving $362.2 million. Revenue from obligation buy bids for the first ten months of the 2022/2023 planning period were up 81.1 percent over the same period last planning period. Revenue from obligation sell offers was up 84.9 percent over the same period last planning period.

Table 13-18 Monthly Balance of Planning Period FTR Auction revenue: January through March, 2023

Monthly Auction	Type	Trade Type	24-Hour	On Peak	Off Peak	Daily Off Peak	Weekend On Peak	All
			Class Type					
Jan-22	Obligations	Buy bids	$28,977,509	$16,759,220	$0	$8,759,706	$5,366,049	$59,862,484
		Sell offers	$2,027,458	$23,929,935	$0	$10,081,126	$7,129,486	$43,168,006
	Options	Buy bids	$608,659	$1,861,955	$0	$839,774	$470,996	$3,781,384
		Sell offers	$1,654,290	$7,118,929	$0	$3,661,808	$2,821,775	$15,256,802
Feb-22	Obligations	Buy bids	($401,711)	$14,435,461	$0	$7,738,678	$5,017,123	$26,789,551
		Sell offers	$2,986,371	$9,502,028	$0	$3,683,879	$2,600,461	$18,772,739
	Options	Buy bids	$390,690	$2,367,369	$0	$961,052	$632,551	$4,351,662
		Sell offers	$1,131,174	$3,764,493	$0	$1,812,244	$1,389,729	$8,097,639
Mar-22	Obligations	Buy bids	($9,527,625)	$15,541,144	$0	$6,945,264	$4,464,356	$17,423,138
		Sell offers	$2,749,686	$6,208,256	$0	$598,070	$1,138,660	$10,694,672
	Options	Buy bids	$134,878	$1,233,783	$0	$705,066	$517,472	$2,591,199
		Sell offers	$872,541	$2,803,604	$0	$1,242,208	$1,129,135	$6,047,487
2021/2022*	Obligations	Buy bids	$130,170,799	$93,071,867	$154,936,269	$0	$0	$378,178,935
		Sell offers	$8,296,880	$98,421,764	$155,017,657	$0	$0	$261,736,301
	Options	Buy bids	$2,675,547	$14,067,533	$17,605,969	$0	$0	$34,349,049
		Sell offers	$19,136,817	$36,088,621	$45,266,394	$0	$0	$100,491,832
	Net Total		$105,412,649	($27,370,984)	($27,741,813)	$0	$0	$50,299,852
2022/2023**	Obligations	Buy bids	$143,199,942	$311,391,138	$85,220,313	$43,196,398	$38,282,199	$621,289,990
		Sell offers	$36,213,051	$267,221,566	$66,590,742	$36,569,440	$32,598,615	$439,193,415
	Options	Buy bids	$5,481,198	$35,102,509	$20,029,176	$7,302,255	$4,367,492	$72,282,631
		Sell offers	$13,650,687	$79,710,373	$24,685,222	$17,937,687	$16,204,756	$152,188,725
	Net Total		$98,817,403	($438,293)	$13,973,526	($4,008,474)	($6,153,681)	$102,190,481

* Shows twelve months for 2021/2022 **Shows ten months for 2022/2023

FTR Target Allocations

FTR target allocations were examined separately by source and sink contribution. Hourly FTR target allocations were divided into those that were benefits and liabilities and summed by sink and by source. Figure 13-6 shows the 10 largest positive and negative FTR target allocations, summed by sink, for the first ten months of the 2022/2023 planning period. The top 10 sinks that produced financial benefit accounted for 25.0 percent of total positive target allocations with the Western Hub accounting for 8.0 percent of all positive target allocations. The top 10 sinks that created liability accounted for 17.0 percent of total negative target allocations with PECO accounting for 4.2 percent of all negative target allocations.

Figure 13-6 Ten largest positive and negative FTR target allocations summed by sink: 2022/2023

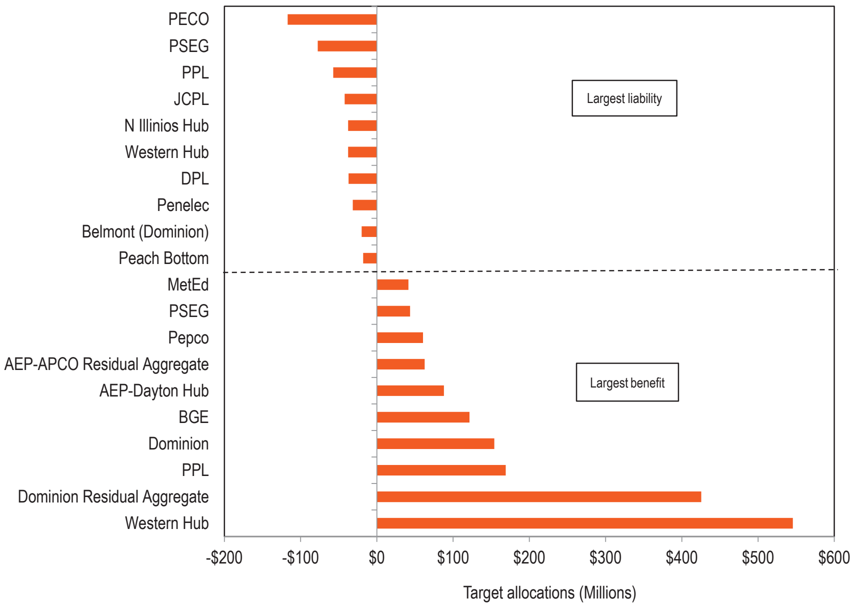


Figure 13-7 Ten largest positive and negative FTR target allocations summed by source: 2022/2023

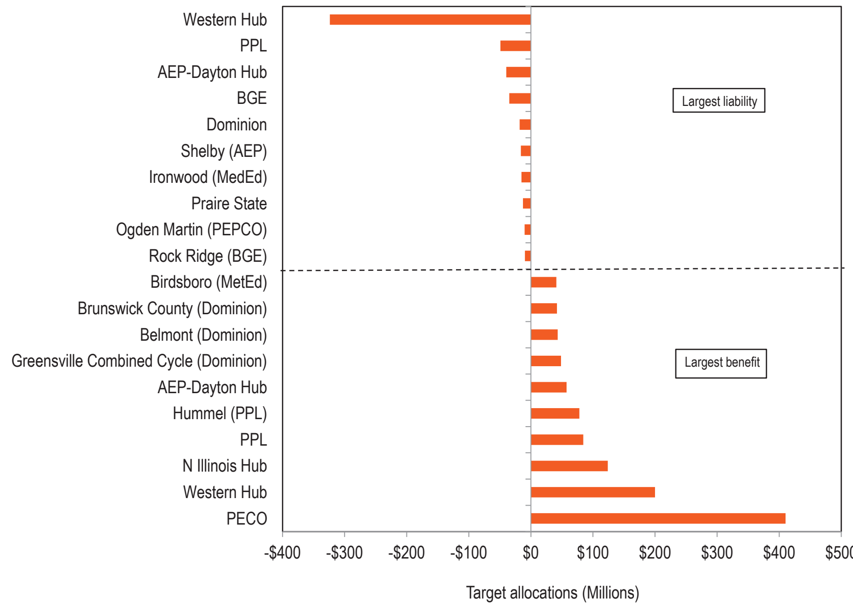


Figure 13-7 shows the 10 largest positive and negative FTR target allocations, summed by source, for the ten months of the 2022/2023 planning period. The top 10 sources with a positive target allocation accounted for 16.5 percent of total positive target allocations with PECO accounting for 6.0 percent of total positive target allocations. The top 10 sources with a negative target allocation accounted for 18.9 percent of all negative target allocations, with the Western Hub accounting for 11.6 percent of total negative target allocations.

The Effect of Fast Start Pricing on FTR Target Allocations

PJM implemented fast start pricing on September 1, 2021, and as a result, PJM produces separate dispatch and pricing solutions. The dispatch run results in dispatch instructions and matching prices, termed dispatch run locational marginal price, or DLMP. The DLMP prices are the prices that would have been the LMPs prior to fast start pricing. The pricing run results in the final prices used in settlements and for FTR target allocations, termed pricing run locational marginal price, or PLMP. The two runs result in different sets of target allocations for the same FTR paths. Table 13-19 compares the target allocations that result from the pricing and dispatch runs for both self scheduled and all other FTRs for the 2021/2022 and the first ten months of the 2022/2023 planning periods. The difference indicates whether the target allocations were increased or decreased as a result of fast start pricing.

Table 13-19 Pricing run and dispatch run FTR Target Allocations: 2021/2022 and 2022/2023 planning periods

Planning Period		Pricing Run	Dispatch Run	Difference	Percent Difference
2021/2022*	Not Self Scheduled	$1,499,077,738.2	$1,497,963,894.6	$1,113,843.6	0.1%
	Self Scheduled	$429,271,338.2	$430,800,597.9	($1,529,259.7)	(0.4%)
	Total	$1,928,349,076.4	$1,928,764,492.5	($415,416.1)	(0.0%)
2022/2023**	Not Self Scheduled	$1,446,613,234.9	$1,393,503,123.4	$53,110,111.5	3.7%
	Self Scheduled	$565,271,991.6	$611,599,419.7	($46,327,428.0)	(8.2%)
	Total	$2,011,885,226.5	$2,005,102,543.1	$6,782,683.5	0.3%

* starting in September 2021

** first ten months of the 2022/2023 planning period

Surplus Congestion Revenue

Surplus congestion revenue is a misnomer. In fact, there is no such thing as surplus congestion revenue. The rights to all congestion revenue belong to load. Surplus congestion revenue, as defined in PJM rules, is an artifact of the flawed design of the current approach to FTR/ARRs.

In the current design, surplus congestion revenue should be allocated to ARR holders because such revenue is part of total congestion revenues. In addition, FTR Auction revenue results from the prices paid by willing FTR buyers and should not be returned to FTR buyers for any reason and should be settled monthly.

Surplus day-ahead congestion is defined as the difference between the day-ahead congestion collected and FTR target allocations. Surplus FTR auction revenue is defined as the difference between the sum of monthly FTR auction revenue from the Long Term, Annual and monthly auctions, and ARR target allocations. Surplus FTR auction revenue can result from high prices in the FTR auctions, and from FTR capacity sold in excess of assigned ARR capacity on specific paths, and FTR capacity sold on paths not available to ARR holders.

Surplus congestion revenue is defined as the sum of the surplus day-ahead congestion revenue and the surplus FTR auction revenue at the end of each month.[32] Beginning with the 2014/2015 planning period, PJM may use surplus FTR auction revenue to pay for the clearing of counter flow FTRs as part of the auction clearing process.[33] The remaining surplus is first used to ensure that ARR target allocations in the month are fully funded. Any remaining surplus is used to pay any shortfall in FTR target allocations for the current month or prior months in the planning period. Any remaining surplus is used to pay any shortfall in FTR target allocations for the entire planning period at the end of the planning period. Any remaining surplus is distributed to ARR holders.[34]

If, at the end of the planning period, all the surplus congestion revenue has been provided to FTR holders and target allocations for the year are not covered, an uplift charge is assigned to FTR holders to cover the net planning period deficiency. An individual participant's uplift charge allocation is the ratio of their share of net positive target allocations to the total net positive target allocations.

Figure 13-8 shows the distribution of the monthly surplus congestion revenue distributed to FTR holders as if it were settled monthly. The figure shows the portions of total monthly surplus, represented by the total height of the bar, that are from day-ahead congestion surplus, represented by the blue portion of the bar, and from auction surplus, represented by the orange portion of the bar. The horizontal green lines represent the amount of revenue that FTRs were paid from the surplus to be made whole for that month. The height of the bar below the green line is the portion of auction surplus that went to FTR holders, and the height of the bar above the green line is the portion that would have gone to ARR holders at the end of the planning period, if nothing changed and this surplus was not provided to FTRs. If a green line is above the bar that means there was not enough surplus congestion in that month to make FTRs whole. For example, September 2020 did not have enough surplus congestion to make FTRs whole. Those FTRs were made whole using surplus revenue from previous months. Three of the first ten months of the 2022/2023 planning period did not have enough revenue to pay FTR target allocations, represented by lines that are entirely above the surplus bars. In the first ten months of the 2022/2023 planning period, $247.6 million was

32 Prior to the 2017/2018 planning period, the surplus congestion revenue was not the simple sum of the surplus FTR auction revenue and surplus day-ahead congestion because there were various cross market charges subtracted from FTR revenue, including M2M and competing use charges, which reduced available surplus congestion revenue.

33 *See* "PJM Manual 6: Financial Transmission Rights," Rev. 29 (Sep. 1, 2022).

34 On May 31, 2018, a rule change was implemented. Effective for the 2018/2019 planning period, surplus day-ahead congestion charges and surplus FTR auction revenue that remain at the end of the Planning Period allocated to ARR holders, rather than to FTR holders. 163 FERC ¶ 61,165 (2018).

paid from individual monthly surplus amounts to cover shortfalls in months with a shortfall.

The market rules should recognize that ARR holders have the right to all surplus congestion revenue, not just the remainder after funding FTRs. The MMU recommends that all FTR auction revenue be distributed to ARR holders monthly, regardless of FTR funding levels. The MMU recommends that, under the current FTR design, all congestion revenue in excess of FTR target allocations be distributed to ARR holders on a monthly basis. In Figure 13-8 the amount represented by each bar would be assigned to ARR holders in every month. In the first ten months of the 2022/2023 planning period, $91.4 million of surplus congestion revenue was paid to FTR holders that would have been paid to ARR holders under the MMU recommendation. The significant increase in surplus congestion revenue starting in January 2022 was the result of increased day-ahead congestion, without a corresponding increase in target allocations. Day-ahead congestion increased by $480.8 million, 31.7 percent, from $1,516.9 million in the first ten months of the 2021/2022 planning period to $1,997.7 million in the first ten months of the 2022/2023. Target allocations increased by $323.8 million, 19.0 percent, from $1,702.6 million in the first ten months of the 2021/2022 planning period to $2,026.4 million in the first ten months of the 2022/2023 planning period. This disconnect between target allocations and congestion is a result of incorrectly defined property rights in the current ARR/FTR market design.

Figure 13-8 Monthly surplus congestion and auction revenue distributed to FTR holders: June 2017 through March 2023[35]

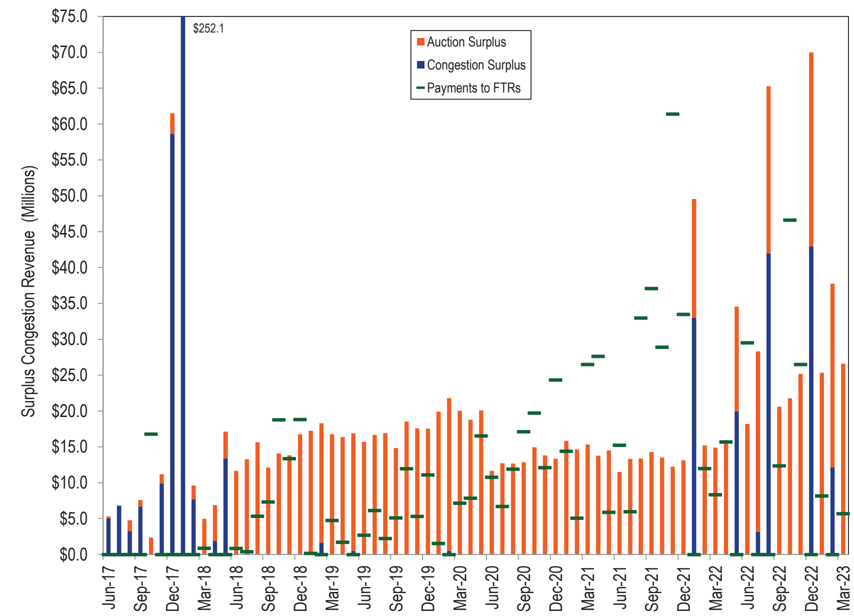


Figure 13-9 shows the surplus FTR auction revenue from the 2011/2012 planning period through the first ten months of the 2022/2023 planning period. Each new planning period introduces a new FTR model, including outages and PJM's discretionary adjustments for revenue adequacy. The differences in the assumptions in the market model can result in large differences in FTR auction surplus and ARR revenue from one planning period to another.

FTR auction revenue is the value that FTR buyers assign to congestion rights that belong to ARR holders. There is no logical or market based reason to assign any part of that auction revenue back to the FTR buyers. It is inconsistent with the operation of a market that sellers are required to return some of the purchase price to buyers if the purchase is less profitable for buyers than expected. Auction revenue from the sale of FTRs should be distributed directly

35 The bar for January 2018 is truncated.

and completely to ARR holders. The MMU recommends that all FTR auction revenue be distributed to ARR holders on a monthly basis.

Figure 13-9 Monthly FTR auction surplus: 2011/2012 through 2022/2023

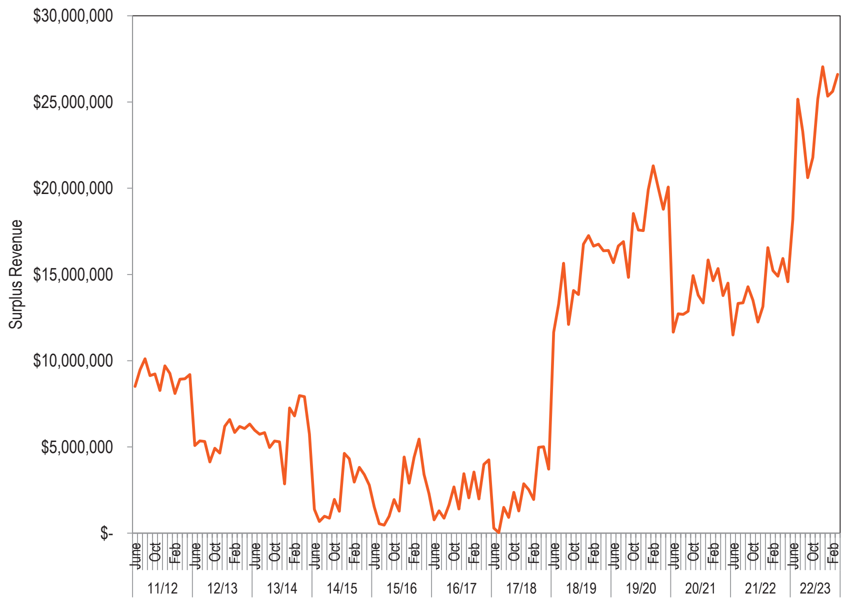


Table 13-20 shows the surplus FTR auction revenue, surplus day-ahead congestion revenue and surplus congestion revenue for planning periods 2010/2011 through the first ten months of the 2022/2023 planning period.

Table 13-20 Surplus FTR Auction Revenue: 2010/2011 through 2022/2023[36]

Planning Period	Surplus FTR Auction Revenue (Millions)	Surplus Day-Ahead Congestion (Millions)	Surplus Congestion Revenue (Millions)
2010/2011	$29.7	($1,218.7)	($449.3)
2011/2012	$108.9	($460.3)	($192.5)
2012/2013	$66.7	($328.5)	($292.3)
2013/2014	$71.7	($715.3)	($678.7)
2014/2015*	$29.0	$139.8	$139.6
2015/2016	$29.6	$56.4	$42.5
2016/2017	$27.9	$97.1	$72.6
2017/2018	$27.4	$344.0	$371.2
2018/2019	$180.8	($68.5)	$112.3
2019/2020	$217.8	($87.9)	$140.7
2020/2021	$166.1	($185.1)	($14.5)
2021/2022	$168.5	$198.0	($29.5)
2022/2023**	$238.8	$28.7	$210.1
Total	$1,362.9	($2,200.2)	($567.9)

*Start of counter flow "buy back"

**First ten months of the 2022/2023 planning period

Revenue Adequacy

FTR revenue adequacy, like surplus congestion revenue, is a misnomer. FTR revenue adequacy, as defined in PJM rules, is an artifact of the flawed design of the current approach to FTR/ARRs. If FTRs only returned congestion to FTR holders, there could be no such thing as revenue inadequacy.

As currently defined in PJM, FTR revenue adequacy simply compares congestion revenues to FTR target allocations. (Target allocations are the CLMP differences between the source and sink of the FTR times the MW of the FTR.) There is no reason to expect congestion revenues to equal FTR target allocations under the path based approach. There are systematic differences between FTR target allocations and actual congestion in aggregate and on a path by path basis. Revenue adequacy is not a benchmark for how well the FTR process is working. Target allocations define the maximum payments to FTRs but target allocations are not congestion. FTR revenue adequacy is not equivalent to the adequacy of ARRs as an offset for load against total congestion. A path specific target allocation is not a guarantee of payment.

36 Total congestion surplus not equal to the sum of the columns in years prior to the 2017/2018 planning period because other charges were subtracted from the congestion surplus.

Actual congestion revenues are not a result of PJM's decisions about the FTR auction model. As a result, the fewer FTRs sold, the higher the probability that congestion will exceed the sum of the FTR target allocations. For example, PJM's subjective decision to reduce available system capability in the ARR/FTR market model through outage selection for the 2014/2015 through 2016/2017 planning periods resulted in a high level of revenue adequacy at the expense of a reduction in available ARRs and associated FTRs. PJM's decisions have included the arbitrary use of higher outage levels and the decision to include additional constraints (closed loop interfaces) both of which reduced the FTRs made available for sale in FTR auctions. PJM's actions have led to a significant reduction in the allocation of Stage 1B and Stage 2 ARRs and therefore a reduction in available FTRs.

While PJM's arbitrary decision to increase outages in the ARR allocation and in the Annual FTR Auction reduced FTR revenue inadequacy, it did not address the Stage 1A ARR over allocation issue directly because Stage 1A ARR allocations cannot be prorated. Instead, PJM's actions for the 2014/2015 through 2016/2017 planning periods resulted in decreased Stage 1B ARR allocations, decreased Stage 2 ARR allocations and decreased FTR capability. The direct assignment of balancing congestion and M2M payments to load beginning in the 2017/2018 planning period increased the congestion revenue available to pay FTR holders. In response, PJM reduced the number of outages taken in the ARR allocation and in the Annual FTR Auction, increasing ARR allocations and FTR availability. The current ARR/FTR design does not serve as an efficient way to ensure that load receives all the congestion revenues or has the ability to receive the auction revenues associated with all the potential congestion revenues. There are several reasons for the disconnect between congestion revenues and ARR/FTR revenues in the current design. The reasons include: the use of generation to load paths rather than a measure of total congestion to assign congestion revenue rights; the failure to provide to ARR holders the full system capability that is provided to FTR purchasers in the Long Term FTR Auction; unavoidable modeling differences such as emergency outages; avoidable modeling differences such as outage modeling decisions; and cross subsidies among and between FTR participants and ARR holders.

Revenue adequacy for ARRs is, for practical purposes, a meaningless concept. Revenue adequacy for ARRs means that FTR buyers collectively pay more than zero for FTRs in FTR auctions, and that those payments were received by ARR holders. For that reason, ARRs have unsurprisingly been revenue adequate for every auction to date. ARR revenue adequacy has nothing to do with the adequacy of ARRs as an offset to total congestion. ARRs can be revenue adequate at the same time that ARRs return only half of congestion to load, or even much less.

Total net FTR auction revenue for the 2021/2022 planning period, before accounting for self scheduling, load shifts or residual ARRs, was $812.6 million. For the first ten months of the 2022/2023 planning period, total net FTR auction revenue was $1,660.4 million.

Table 13-21 presents the PJM FTR revenue detail for the 2021/2022 planning period and the first ten months of the 2022/2023 planning period. This includes ARR target allocations from the Annual ARR Allocation and net revenue sources from the Long Term, Annual and Monthly Balance of Planning Period FTR Auctions.[37] In this table, under the new balancing congestion and M2M payment rules, any negative congestion is from day-ahead congestion and does not include balancing congestion. A negative deficiency is a surplus, which will be distributed to ARR holders at the end of the planning period, while a positive deficiency is a shortfall, which will be charged as FTR uplift at the end of the planning period.

37 The final ARR values may change if load shifts.

Table 13-21 Total annual ARR and FTR revenue detail (Dollars (Millions)): 2021/2022 and 2022/2023

Accounting Element	2021/2022	2022/2023
ARR information		
ARR target allocations	$634.2	$1,343.2
ARR credits	$634.2	$1,343.2
FTR auction revenue	$812.6	$1,660.4
Annual FTR Auction net revenue	$692.4	$1,501.5
Long Term FTR Auction net revenue	$69.9	$56.8
Monthly Balance of Planning Period FTR Auction net revenue	$50.3	$102.2
Surplus auction revenue		
ARR Surplus	$168.5	$317.2
ARR payout ratio	100%	100%
FTR targets		
Positive target allocations	$2,902.9	$2,145.3
Negative target allocations	($652.2)	($347.0)
FTR target allocations	$2,250.6	$1,798.4
Adjustments:		
Adjustments to FTR target allocations	$0.0	$0.0
Total FTR targets	$2,250.6	$1,798.4
FTR payout ratio	99.0%	100.0%
FTR revenues		
ARR excess	$168.5	$317.2
Congestion		
Net Negative Congestion (enter as negative)	$0.0	($0.0)
Hourly congestion revenue	$2,052.6	$1,997.7
M2M Payments(credit to PJM minus credit to M2M entity)	$0.0	$0.0
Adjustments:		
Surplus revenues carried forward into future months	$3.6	$0.0
Surplus revenues distributed back to previous months	$97.9	$37.5
Other adjustments to FTR revenues	$0.0	$0.0
Total FTR revenues		
Surplus revenues distributed to other months	$101.5	$37.5
Net Negative Congestion charged to DA Operating Reserves	$0.0	$0.0
Total FTR congestion credits	$2,221.1	$2,026.4
Total congestion credits(includes end of year distribution)	$2,221.1	$2,026.4
Remaining deficiency	$29.5	($210.1)

* First ten months of 2022/2023

FTR target allocations are defined based on hourly CLMP differences in the day-ahead energy market for FTR paths. FTR credits are paid to FTR holders and, depending on market conditions, can be less than the target allocations but are capped at target allocations. Table 13-22 lists the FTR revenues, target allocations, credits, payout ratios, congestion credit deficiencies and excess congestion charges by month for the 2021/2022 planning period and the first 10 months of the 2022/20023 planning period.

The total row in Table 13-22 is not the sum of each of the monthly rows because the monthly rows may include excess revenues carried forward from prior months and excess revenues distributed back from later months.

Table 13-22 Monthly FTR accounting summary (Dollars (Millions)): 2021/2022 and 2022/2023

Period	FTR Revenues (with adjustments)	FTR Target Allocations	FTR Payout Ratio (original)	FTR Credits (with adjustments)	FTR Payout Ratio (with adjustments)	Monthly Credits Surplus (with adjustments)	Monthly Credits Deficiency (with adjustments)
Jun-21	$97.7	$101.5	96.3%	$101.5	100.0%	$0.0	$0.0
Jul-21	$86.5	$79.1	100.0%	$86.5	100.0%	$7.4	$0.0
Aug-21	$121.5	$141.1	86.1%	$141.1	100.0%	$0.0	$0.0
Sep-21	$110.7	$133.5	82.9%	$133.5	100.0%	$0.0	$0.0
Oct-21	$126.7	$142.1	89.2%	$142.1	100.0%	$0.0	$0.0
Nov-21	$220.9	$270.1	81.8%	$260.9	96.6%	$0.0	($44.0)
Dec-21	$126.1	$146.4	86.1%	$126.1	86.1%	$0.0	($20.3)
Jan-22	$459.8	$410.2	100.0%	$459.6	100.0%	$49.6	$0.0
Feb-22	$174.1	$170.9	100.0%	$174.1	100.0%	$3.2	$0.0
Mar-22	$114.2	$107.6	100.0%	$114.2	100.0%	$6.6	$0.0
Apr-22	$161.9	$161.6	100.0%	$161.9	100.0%	$0.2	$0.0
May-22	$421.0	$386.4	100.0%	$421.0	100.0%	$34.5	$0.0
			Summary for Planning Period 2021/2022				
Total	$2,221.1	$2,250.6		$2,322.3			($29.5)
Jun-22	$220.2	$231.5	95.1%	$231.5	100.0%	$0.0	$0.0
Jul-22	$248.7	$220.4	100.0%	$248.7	100.0%	$28.3	$0.0
Aug-22	$378.9	$313.7	100.0%	$378.9	100.0%	$65.3	$0.0
Sep-22	$269.1	$260.9	100.0%	$269.1	100.0%	$8.2	$0.0
Oct-22	$183.2	$208.0	88.1%	$208.0	100.0%	$0.0	$0.0
Nov-22	$240.4	$241.8	99.4%	$241.8	100.0%	$0.0	$0.0
Dec-22	$392.0	$322.1	100.0%	$392.0	100.0%	$70.0	$0.0
Jan-23	$94.6	$77.5	100.0%	$94.6	100.0%	$17.2	$0.0
Feb-23	$128.4	$90.7	100.0%	$128.4	100.0%	$37.7	$0.0
Mar-23	$80.8	$59.9	100.0%	$80.8	100.0%	$20.9	$0.0
			Summary for Planning Period 2022/2023				
Total	$2,236.5	$2,026.4		$2,274.0		$210.1	

* First ten months of the 2022/2023 planning period

Figure 13-10 shows the original PJM reported FTR payout ratio by month, excluding excess revenue distribution, for January 2004 through March 2023. The months with payout ratios above 100 percent have congestion revenue greater than the target allocations and the months with payout ratios under 100 percent have congestion revenue that is less than the target allocations. Figure 13-10 also shows the payout ratio after distributing surplus congestion revenue across months within the planning period. The payout ratio for months with a payout ratio less than 100 percent in the current planning period may change if surplus congestion revenue is collected in the remainder of the planning period and assigned to prior months.

Figure 13-10 FTR payout ratio by month, excluding and including excess revenue distribution: January 2004 through March 2023

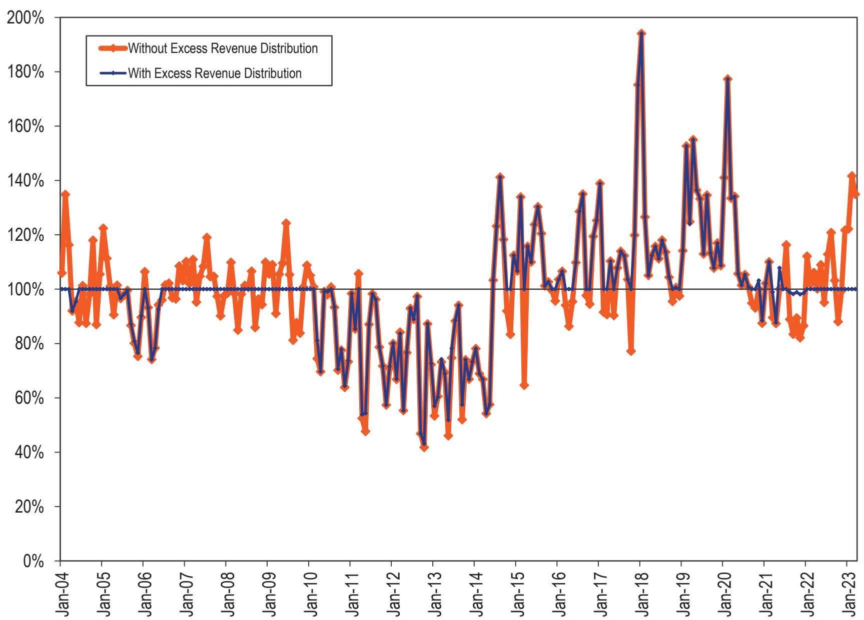


Table 13-23 shows the FTR payout ratio by planning period from the 2003/2004 planning period forward. The 2013/2014 planning period includes the additional revenue from unallocated congestion charges from Balancing Operating Reserves. Beginning with the 2018/2019 planning period payments to FTRs are limited to 100 percent of the target allocations.

The first ten months of the 2022/2023 planning period had a payout ratio of 100.0 percent.

Table 13-23 Reported FTR payout ratio by planning period[38]

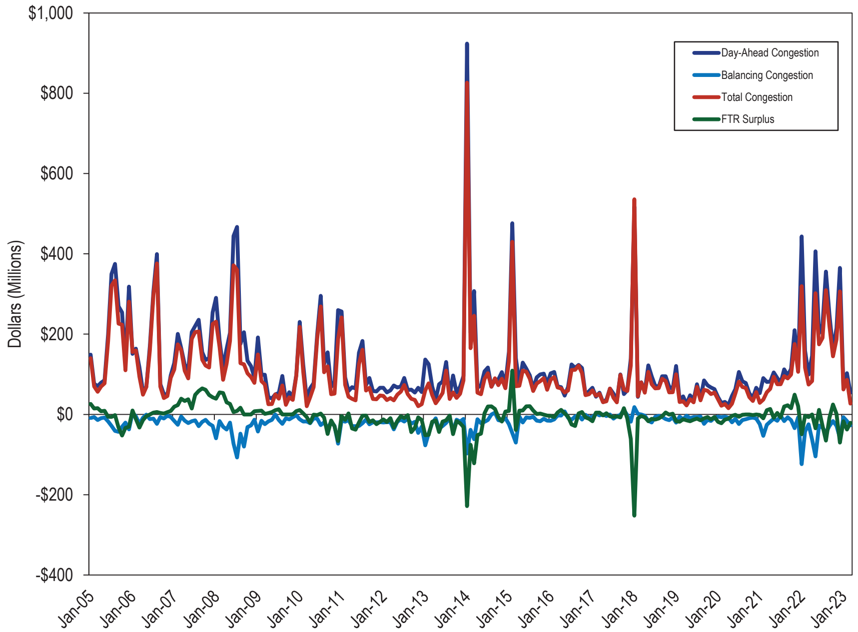
Planning Period	FTR Payout Ratio
2003/2004	97.7%
2004/2005	100.0%
2005/2006	90.7%
2006/2007	100.0%
2007/2008	100.0%
2008/2009	100.0%
2009/2010	96.9%
2010/2011	85.0%
2011/2012	80.6%
2012/2013	67.8%
2013/2014	72.8%
2014/2015	116.2%
2015/2016	106.8%
2016/2017	112.6%
2017/2018	138.5%
2018/2019	100.0%
2019/2020	100.0%
2020/2021	98.7%
2021/2022	99.0%
2022/2023	100.0%

* First ten months of 2022/2023

38 The actual payout ratios for the 2006/2007, 2007/2008, and 2008/2009 planning periods may have exceeded 100 percent.

Figure 13-11 shows the day-ahead balancing and total congestion payments from 2005 through the first three months of 2023.

Figure 13-11 FTR surplus and day-ahead, balancing and total congestion: 2005 through March 2023



Target Allocations and Congestion by Constraint

One of the reasons that the current path based ARR/FTR market design does not provide a reasonable way to return congestion to load is because target allocations on the FTR paths do not align with congestion based on actual network use. A comparison of the FTR target allocations for individual constraints to the day-ahead and total congestion by constraint provides evidence of this misalignment. Total congestion is the sum of day-ahead and balancing congestion. If FTR target allocations on some paths are significantly greater than actual congestion and FTR target allocations on other paths are significantly less than actual congestion, this is evidence of a serious flaw in the design. It is evidence that the FTR design is not meeting its goal of paying out congestion, regardless of the recipients.

FTR target allocations are the result of constraints on day-ahead paths in the energy market. Any specific FTR path may be affected by multiple constraints. Constraints that result in FTR target allocations greater than the congestion that results from those constraints mean that the FTR target allocations are greater than the actual congestion. Figure 13-12 shows the constraints that are the top 10 sources of positive FTR target allocations, for the first ten months of the 2022/2023 planning period. Figure 13-12 also shows the corresponding day-ahead congestion and total congestion that result from the identified constraints.

Figure 13-12 Top ten constraint sources of positive FTR target allocations: June 2022 through March 2023

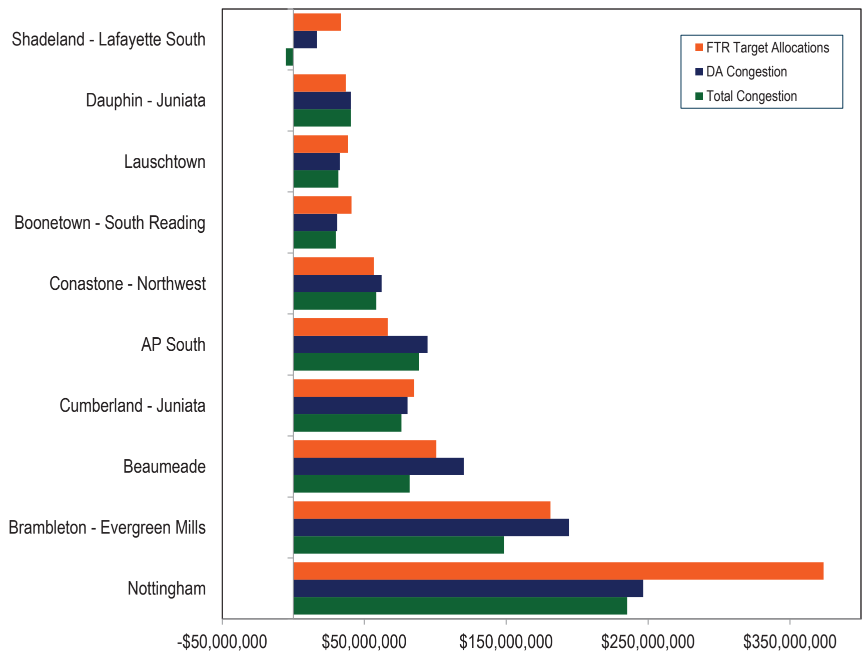
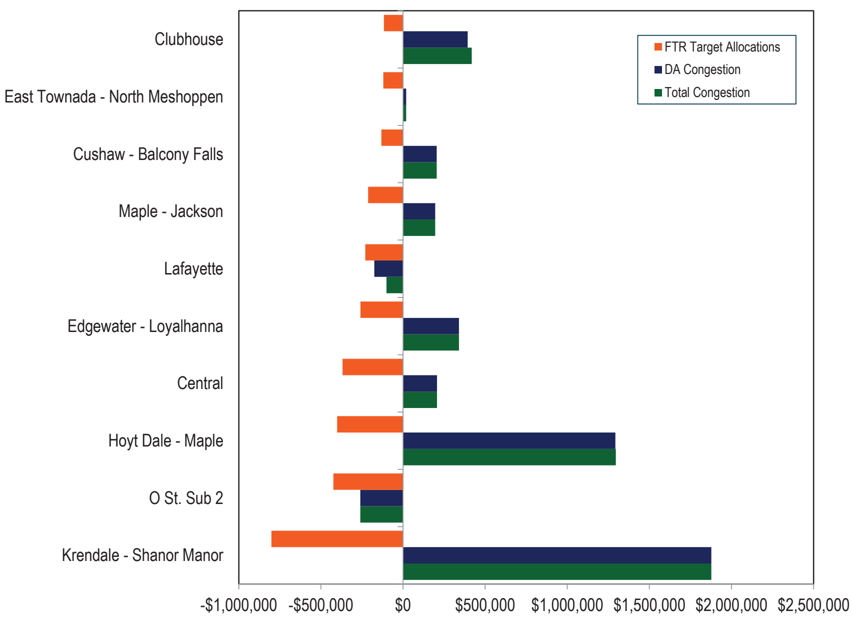


Figure 13-13 shows the constraints that are the top 10 sources of negative FTR target allocations, for the first ten months of the 2022/2023 planning period. Figure 13-13 also shows the corresponding day-ahead congestion and total congestion that result from the identified constraint.

In the first ten months of the 2022/2023 planning period, there were 42 constraints that were the source of negative target allocations. Of the 50 constraints with negative target allocations, 47 resulted in positive actual total congestion. Constraints that contribute positive congestion revenues and have negative FTR target allocations are a source of funds used in the settlement process to pay for FTR target allocations on FTR paths that are over allocated relative to actual congestion.

Figure 13-13 Top ten constraint sources of negative FTR target allocations: June 2022 through March 2023



ARRs as an Offset to Congestion for Load

Load pays 100 percent of congestion revenues. FTRs, and later ARRs, were intended to return congestion revenues to load to offset an unintended consequence of locational marginal pricing. With the implementation of the current, path based FTR/ARR design, the purpose of FTRs has been subverted. The inconsistencies between actual network solutions used to serve load and path based rights available to load cause a misalignment of congestion paid by load and the congestion paid to load, in aggregate and on a specific load basis. These inconsistencies between actual network use and path based rights cause cross subsidies between ARR holders and FTR holders and among ARR holders. One result of this misalignment is that individual zones have very different offsets due to the location of their path based ARRs compared to their actual congestion costs from actual network use.

Table 13-24 shows the ARR and FTR revenue paid to load, the congestion offset available to load with and without allocating balancing congestion to load and the congestion offset when surplus congestion revenue is allocated to load. The highlighted offsets are the actual offsets based on the rules that were effective in that planning period. The pre 2017/2018 offset is calculated as the ARR credits and the FTR credits excluding balancing congestion and M2M payments, divided by the total day-ahead congestion and the load share of balancing and M2M payments.

Total ARR and self scheduled FTR revenue offset 75.6 percent of total congestion costs for the first ten months of the 2022/2023 planning period.

Table 13-24 ARR and self scheduled FTR total congestion offset (in millions) for ARR holders: 2011/2012 through 2022/2023

	Revenue								Pre 2017/2018 (Without Balancing)		2017/2018 (With Balancing)		Post 2017/2018 (With Balancing and Surplus)		Effective Offset	
Planning Period	ARR Credits	Unadjusted FTR Credits	Day Ahead Congestion	Balancing + M2M Congestion	Total Congestion	Surplus Revenue Pre 2017/2018 Rules	Surplus Revenue 2017/2018 Rules	Post 2017/2018 Rules	Total ARR/ FTR Offset	Percent Offset	Current Revenue Received	Percent Offset	New Revenue Received	New Offset	Cumulative Revenue	Offset
2011/2012	$515.6	$310.0	$1,025.4	($275.7)	$749.7	($50.6)	$35.6	$113.9	$775.0	103.4%	$585.5	78.1%	$663.8	88.5%	$775.0	103.4%
2012/2013	$356.4	$268.4	$904.7	($379.9)	$524.8	($94.0)	$18.4	$62.1	$530.7	101.1%	$263.2	50.2%	$306.9	58.5%	$530.7	101.1%
2013/2014	$339.4	$626.6	$2,231.3	($360.6)	$1,870.6	($139.4)	($49.0)	($49.0)	$826.5	44.2%	$556.3	29.7%	$556.3	29.7%	$826.5	44.2%
2014/2015	$487.4	$348.1	$1,625.9	($268.3)	$1,357.6	$36.7	$111.2	$400.6	$872.2	64.2%	$678.4	50.0%	$967.8	71.3%	$872.2	64.2%
2015/2016	$641.8	$209.2	$1,098.7	($147.6)	$951.1	$9.2	$42.1	$188.9	$860.2	90.4%	$745.5	78.4%	$892.3	93.8%	$860.2	90.4%
2016/2017	$648.1	$149.9	$885.7	($104.8)	$780.8	$15.1	$36.5	$179.0	$813.1	104.1%	$729.6	93.4%	$872.1	111.7%	$813.1	104.1%
2017/2018	$429.6	$212.3	$1,322.1	($129.5)	$1,192.6	$52.3	$80.4	$370.7	$694.2	58.2%	$592.8	49.7%	$883.1	74.1%	$592.8	49.7%
2018/2019	$531.6	$130.1	$832.7	($152.6)	$680.0	($5.8)	$16.2	$112.2	$655.87	96.4%	$525.3	77.2%	$621.3	91.4%	$621.3	91.4%
2019/2020	$547.6	$91.9	$612.1	($169.4)	$442.7	($1.6)	$21.6	$157.8	$637.9	144.1%	$491.7	111.1%	$627.9	141.8%	$627.9	141.8%
2020/2021	$392.7	$179.9	$899.6	($256.2)	$643.4	($43.2)	($0.0)	($0.0)	$529.31	82.3%	$316.4	49.2%	$316.4	49.2%	$316.4	49.2%
2021/2022	$469.7	$500.5	$2,069.2	($457.4)	$1,611.8	($104.6)	($2.9)	($2.9)	$865.6	53.7%	$509.9	31.6%	$509.9	31.6%	$509.9	31.6%
2022/2023*	$829.4	$572.8	$1,997.7	($420.6)	$1,577.1	($59.5)	$59.4	$210.1	$1,342.6	85.1%	$1,040.9	66.0%	$1,191.7	75.6%	$1,191.7	75.6%
Total	$6,189.1	$3,599.7	$15,504.9	($3,122.7)	$12,382.3	($385.4)	$369.5	$1,743.4	$9,403.4	75.9%	$7,035.6	56.8%	$8,409.5	67.9%	$8,537.7	69.0%

* First ten months of the 2022/2023 planning period

Table 13-24 illustrates the inadequacies of the ARR/FTR design. The goal of the design should be to give the rights to 100 percent of the congestion revenues to the load.

Table 13-25 shows the cumulative offset and shortfall using the rules that were effective in the given planning period to calculate the ARR/FTR revenue. The cumulative offset, beginning in the 2011/2012 planning period, is the sum of the revenue received for that planning period and all previous planning periods divided by the total congestion for that planning period and all previous planning periods. The cumulative shortfall is the cumulative difference between the ARR holders' revenue and the congestion they paid, for the planning period and prior planning periods.

From the 2011/2012 planning period through the first ten months of the 2022/2023 planning period, the cumulative offset, the cumulative return of congestion to load, was only 69.0 percent based on the rules that were in place for each planning period. Load has been underpaid by $3.8 billion from the 2011/2012 planning period through the first ten months of the 2022/2023 planning period.

Table 13-25 ARR and self scheduled FTR cumulative offset for ARR holders: 2011/2012 through 2022/2023

Planning Period	Cumulative Offset	Cumulative Shortfall (Millions)
2011/2012	103.4%	$25.3
2012/2013	102.4%	$31.2
2013/2014	67.8%	($1,012.9)
2014/2015	66.7%	($1,498.3)
2015/2016	70.9%	($1,589.2)
2016/2017	75.0%	($1,556.9)
2017/2018	71.0%	($2,156.7)
2018/2019	72.7%	($2,215.4)
2019/2020	76.3%	($2,030.2)
2020/2021	74.4%	($2,357.2)
2021/2022	68.0%	($3,459.1)
2022/2023	69.0%	($3,844.6)

Zonal ARR Congestion Offset

Zonal ARR congestion offsets vary significantly across zones. There is no good reason that this should be the result of a system designed to return congestion to load. PJM has offered no explanation for this result. This outcome is a direct result of the flawed definition of congestion and of the method for assigning rights to congestion to ARR holders. The results show that path based ARR assignments in the current path based ARR/FTR design are not aligned with actual network use by load, and are therefore not aligned with how congestion is actually paid by load on actual network usage. Due to this misalignment of ARR rights relative to actual network usage, individual loads cannot claim the congestion they paid through assigned ARRs. The misalignment of path based ARR rights produces cross subsidies among ARR holders.

ARRs are allocated to zonal load based on historical generation to load transmission contract paths, in many cases based on 1999 contract paths. ARRs are allocated within zones based on zonal base load (Stage 1A) and zonal peak loads (other stages). ARR revenue is the result of the prices that result from the sale of FTRs through the FTR auctions. ARR revenue for each zone is the revenue for the ARRs that sink in each zone.

Congestion paid by load in a zone is the total difference between what the zonal load pays in congestion charges net of payments to the generation that serves the zonal load, including generation in the zone and outside the zone.[39]

Table 13-26 shows the day-ahead congestion and balancing congestion and M2M charges paid by load in each zone along with the congestion offsets paid to load: FTR auction revenue; self scheduled FTR revenue adjusted by the payout ratio for FTRs if below 100 percent; and the allocation of end of planning period surplus.[40] The offset for the first ten months of the 2022/2023 planning period assigns the current surplus revenue at the end of the quarter to ARR holders. Table 13-26 also shows payments by load for balancing congestion and M2M payments. The total congestion offset paid to load is the sum of all of those credits and charges.

The zonal offset percentage shown in Table 13-26 is the sum of the congestion related revenues (offset) paid to load in each zone divided by the total congestion payment made by load in each zone.

39 *See* "Constraint Based Congestion Calculations," PJM ARR FTR Market Task Force (July 17, 2020) <https://www.pjm.com/-/media/committees-groups/task-forces/afmtf/2020/20200722/20200722-item-03a-constraint-based-congestion-calculations.ashx>.

40 See *2020 State of the Market Report for PJM*, Volume II, Section 11: Congestion and Marginal Losses

Table 13-26 Zonal ARR and self scheduled FTR total congestion offset (in millions) for ARR holders: 2022/2023 planning period

Zone	ARR Credits	Adjusted FTR Credits	Balancing+ M2M Charge	Surplus Allocation	Total Offset	Day Ahead Congestion	Balancing Congestion	M2M Payments	Total Congestion	Offset
ACEC	$2.9	$0.1	($5.11)	$0.58	($1.5)	$20.6	($3.6)	($1.6)	$15.5	(9.8%)
AEP	$68.7	$88.6	($62.8)	$28.7	$123.2	$314.8	($43.4)	($19.4)	$252.0	48.9%
APS	$58.8	$26.1	($25.2)	$16.1	$75.8	$123.6	($17.7)	($7.5)	$98.4	77.0%
ATSI	$32.6	$0.7	($32.3)	$6.1	$7.1	$154.5	($22.2)	($10.1)	$122.2	5.8%
BGE	$122.0	$5.6	($15.8)	$23.2	$134.9	$79.6	($11.1)	($4.7)	$63.9	211.3%
COMED	$35.4	$0.0	($44.7)	$6.5	($2.8)	$211.8	($30.5)	($14.3)	$167.1	(1.7%)
DAY	$7.6	$0.9	($8.6)	$1.5	$1.4	$38.1	($6.0)	($2.6)	$29.6	4.8%
DOM	$40.2	$395.5	($66.1)	$7.5	$377.2	$316.6	($48.5)	($17.6)	$250.5	150.5%
DPL	$69.5	$8.3	($11.6)	$1.7	$67.9	$74.6	($8.8)	($2.9)	$62.9	107.9%
DUKE	$36.8	$6.8	($13.3)	$33.0	$63.2	$60.5	($9.3)	($4.0)	$47.2	134.0%
DUQ	$9.2	$0.2	($6.6)	$14.6	$17.4	$23.5	($4.5)	($2.0)	$16.9	103.2%
EKPC	$5.7	$0.1	($6.6)	$1.0	$0.2	$31.9	($4.6)	($2.1)	$25.2	0.7%
EXT	$1.3	$0.0	($10.1)	$0.0	($8.7)	$37.9	($10.1)	$0.0	$27.8	(31.4%)
JCPLC	$6.3	$0.0	($13.3)	$1.2	($5.8)	$63.3	($9.8)	($3.4)	$50.0	(11.6%)
MEC	$38.8	$3.2	($9.0)	$7.7	$40.7	$38.4	($6.6)	($2.4)	$29.3	138.8%
OVEC	$0.0	$0.0	($0.4)	$0.0	($0.4)	$3.4	($0.4)	$0.0	$3.0	(14.1%)
PE	$15.9	$7.5	($8.7)	$4.4	$19.1	$41.3	($6.1)	($2.6)	$32.6	58.5%
PECO	$22.0	$10.4	($19.5)	$5.6	$18.5	$90.8	($13.5)	($6.0)	$71.3	26.0%
PEPCO	$59.9	$4.4	($14.5)	$11.7	$61.4	$71.2	($10.2)	($4.3)	$56.7	108.3%
PPL	$114.3	$11.6	($23.4)	$23.1	$125.6	$102.3	($17.1)	($6.3)	$78.9	159.2%
PSEG	$80.7	$2.8	($22.2)	$15.9	$77.1	$93.8	($15.5)	($6.7)	$71.6	107.7%
REC	$0.7	$0.0	($0.8)	$0.1	$0.1	$5.2	($0.5)	($0.2)	$4.4	2.6%
Total	$829.4	$572.8	($420.6)	$210.1	$1,191.7	$1,997.7	($300.0)	($120.6)	$1,577.1	75.6%

The total congestion offset paid to loads in the first ten months of the 2022/2023 planning period was 75.6 percent of congestion costs. The results vary significantly by zone. Loads in some zones, like BGE, receive substantially more in offsets than their total congestion payments. Loads in other zones, like ATSI, receive substantially less in offsets than their total congestion payments. The offsets are a function of the assignment of ARRs and the valuation of ARRs in the FTR auctions.

The amount and proportion of the offset that can be realized by load serving entities via their ARR allocations varies by planning period. The offsets are a function of the assignment of ARRs relative actual network sources of congestion paid, the valuation of ARRs in the FTR auctions and the congestion revenue from self scheduled ARRs. If the prices for FTRs are high relative to realized congestion, the offset provided by ARR is increased relative to cases where the prices for FTRs are low relative to realized congestion. While the amount of congestion that is returned to the load varies by planning period, PJM's ARR/FTR design has consistently failed to return the congestion revenues to the load that paid it. It is not possible for load to recover all of the congestion that they pay under the current design in which the rights to congestion revenues are assigned based on fictitious contract paths.

Offset if all ARRs are Held as ARRs

Table 13-27 shows the total congestion offset that would be available to ARR holders via allocated ARRs, by zone, if the ARRs holders held all their allocated ARRs in the 2020/2021, 2021/2022, and the first ten months of the 2022/2023 planning period and did not self schedule any.

Table 13-27 Offset available to load if all ARRs are held: 2020/2021 through 2022/2023 planning periods

	20/21 Planning Period				21/22 Planning Period				22/23 Planning Period			
	ARR Held TA	Bal+M2M Charges	Congestion+ M2M	Offset	ARR Held TA	Bal+M2M Charges	Congestion+ M2M	Offset	ARR Held TA	Bal+M2M Charges	Congestion+ M2M	Offset
ACEC	$4.4	($2.7)	$5.5	31.2%	$4.0	($5.2)	$14.8	(8.0%)	$3.2	($5.1)	$15.5	(12.5%)
AEP	$85.3	($38.1)	$110.9	42.6%	$84.2	($65.7)	$240.4	7.7%	$155.9	($62.8)	$252.0	36.9%
APS	$50.5	($14.8)	$45.2	79.0%	$43.3	($29.7)	$122.8	11.0%	$87.9	($25.2)	$98.4	63.7%
ATSI	$20.5	($19.5)	$50.6	2.1%	$26.3	($32.3)	$117.9	(5.1%)	$33.1	($32.3)	$122.2	0.6%
BGE	$61.1	($9.1)	$24.8	209.2%	$102.8	($17.0)	$59.9	143.2%	$126.2	($15.8)	$63.9	172.9%
COMED	$43.2	($28.5)	$78.3	18.8%	$43.0	($44.7)	$159.9	(1.1%)	$35.4	($44.7)	$167.1	(5.6%)
DAY	$6.4	($5.3)	$11.0	9.8%	$6.1	($8.6)	$26.2	(9.6%)	$8.3	($8.6)	$29.6	(1.0%)
DOM	$67.5	($37.9)	$87.9	33.7%	$87.1	($22.0)	$370.9	17.5%	$9.3	($66.1)	$250.5	(22.6%)
DPL	$32.8	($6.7)	$36.2	72.0%	$50.9	($80.3)	($21.1)	139.2%	$179.5	($11.6)	$62.9	266.7%
DUKE	$28.8	($8.4)	$17.4	117.5%	$27.8	($12.3)	$23.7	65.3%	$79.5	($13.3)	$47.2	140.3%
DUQ	$5.8	($4.0)	$6.2	28.7%	$6.7	($6.4)	$45.3	0.5%	$40.5	($6.6)	$16.9	200.9%
EKPC	$3.0	($4.2)	$8.4	(13.3%)	$3.9	($7.0)	$21.9	(14.2%)	$5.7	($6.6)	$25.2	(3.7%)
EXT	$0.5	($13.8)	$11.0	(120.7%)	$0.7	($9.9)	$19.9	(46.2%)	$1.3	($10.1)	$27.8	(31.4%)
JCPLC	$6.1	($6.1)	$12.9	(0.1%)	$2.1	($12.8)	$39.0	(27.4%)	$6.3	($13.3)	$50.0	(13.9%)
MEC	$3.9	($5.3)	$16.5	(8.4%)	$9.3	($11.6)	$33.2	(6.7%)	$41.7	($9.0)	$29.3	111.3%
OVEC	NA	($0.3)	$0.9	(28.8%)	NA	($0.4)	$1.5	(29.4%)	NA	($0.4)	$3.0	(14.1%)
PE	$9.3	($6.5)	$16.4	16.7%	$13.1	($18.5)	$31.8	(17.2%)	$30.5	($8.7)	$32.6	66.7%
PECO	$15.1	($10.9)	$24.9	17.0%	$21.5	($12.0)	$78.0	12.1%	$23.8	($19.5)	$71.3	6.0%
PEPCO	$29.1	($8.3)	$20.5	101.6%	$31.3	($15.5)	$53.8	29.3%	$63.6	($14.5)	$56.7	86.5%
PPL	$26.1	($11.5)	$30.8	47.4%	$37.7	($21.5)	$103.3	15.7%	$125.8	($23.4)	$78.9	129.8%
PSEG	$24.7	($13.9)	$25.0	43.2%	$35.3	($23.1)	$76.0	16.1%	$86.3	($22.2)	$71.6	89.5%
REC	$0.2	($0.6)	$2.1	(17.0%)	$0.3	($0.8)	$5.3	(9.5%)	$0.7	($0.8)	$4.4	(0.5%)
Total	$524.3	($256.2)	$643.4	41.7%	$637.1	($457.4)	$1,624.6	11.1%	$1,144.4	($420.6)	$1,577.1	45.9%

* First ten months of the 2022/2023 planning period

Offset if all ARRs are Self Scheduled

Table 13-28 shows the total congestion offset that would be available to ARR holders via allocated ARRs, by zone, if the ARR holders self scheduled all their ARRs received in the annual auction process as FTRs in the 2020/2021, 2021/2022 planning periods, and the first ten months of the 2022/2023 planning period. Market rules allow ARRs available in the annual auction process to be self scheduled as FTRs. Any ARRs awarded monthly as residual ARRs cannot be self scheduled but provide ARR revenue based on monthly auction results. The calculated self scheduled FTR target allocations assume a 100 percent payout ratio. The results show that the recovery of congestion varies significantly by zone and that the load in some zones recovers more than the congestion paid and the load in other zones recovers less. This result is not consistent with a rational FTR/ARR design under which all load would be returned their congestion, but no more and no less.

Table 13-28 Offset available to load if all ARRs self scheduled: 2020/2021 through 2022/2023 planning periods

	20/21 Planning Period					21/22 Planning Period					22/23 Planning Period*				
	SS FTR	Residual ARR Credits	Bal+M2M Charges	Congestion+ M2M	Offset	SS FTR	Residual ARR Credits	Bal+M2M Charges	Congestion+ M2M	Offset	SS FTR	Residual ARR Credits	Bal+M2M Charges	Congestion+ M2M	Offset
ACEC	$1.8	$0.3	($2.7)	$5.5	(11.1%)	$0.4	$0.1	($5.2)	$14.8	(31.4%)	$2.7	$0.0	($5.1)	$15.5	(15.6%)
AEP	$77.3	$1.2	($38.1)	$110.9	36.4%	$132.5	$0.5	($65.7)	$240.4	28.0%	$188.8	$1.0	($62.8)	$252.0	50.4%
APS	$42.0	$0.2	($14.8)	$45.2	60.7%	$93.3	$1.6	($29.7)	$122.8	53.1%	$63.0	$7.9	($25.2)	$98.4	46.5%
ATSI	$30.7	$0.0	($19.5)	$50.6	22.1%	$47.3	$0.0	($32.3)	$117.9	12.7%	$72.5	$0.7	($32.3)	$122.2	33.5%
BGE	$79.7	$0.2	($9.1)	$24.8	285.0%	$147.0	$0.1	($17.0)	$59.9	217.3%	$165.8	$0.0	($15.8)	$63.9	234.9%
COMED	$69.6	$0.0	($28.5)	$78.3	52.5%	$51.9	$0.2	($44.7)	$159.9	4.6%	$27.8	$0.5	($44.7)	$167.1	(9.9%)
DAY	$8.0	$0.0	($5.3)	$11.0	24.9%	$7.1	$0.2	($8.6)	$26.2	(4.7%)	$9.4	$0.0	($8.6)	$29.6	2.9%
DOM	$117.0	$1.6	($37.9)	$87.9	91.8%	$556.6	$11.5	($22.0)	$370.9	147.3%	$592.9	$19.2	($66.1)	$250.5	218.0%
DPL	$56.4	$5.7	($6.7)	$36.2	153.1%	$52.3	$2.9	($80.3)	($21.1)	119.3%	$57.7	$1.0	($11.6)	$62.9	74.7%
DUKE	$40.9	$0.0	($8.4)	$17.4	187.5%	$50.8	$0.7	($12.3)	$23.7	165.4%	$70.4	$0.0	($13.3)	$47.2	120.9%
DUQ	$8.9	$0.0	($4.0)	$6.2	79.7%	$7.0	$0.0	($6.4)	$45.3	1.2%	$12.5	$0.0	($6.6)	$16.9	35.4%
EKPC	$6.6	$0.0	($4.2)	$8.4	29.3%	$10.1	$0.0	($7.0)	$21.9	14.2%	$11.1	$0.0	($6.6)	$25.2	17.9%
EXT	$0.3	$0.0	($13.8)	$11.0	(122.3%)	$1.9	$0.0	($9.9)	$19.9	(40.0%)	NA	$0.0	($10.1)	$27.8	(36.2%)
JCPLC	$0.9	$0.0	($6.1)	$12.9	(40.1%)	$4.4	$0.0	($12.8)	$39.0	(21.7%)	$4.4	$0.0	($13.3)	$50.0	(17.7%)
MEC	$8.0	$0.0	($5.3)	$16.5	16.6%	$31.3	$0.0	($11.6)	$33.2	59.5%	$48.5	$0.0	($9.0)	$29.3	134.7%
OVEC	NA	$0.0	($0.3)	$0.9	(28.8%)	NA	$0.0	($0.4)	$1.5	(29.4%)	NA	$0.0	($0.4)	$3.0	(14.1%)
PE	$13.5	$0.0	($6.5)	$16.4	42.8%	$29.7	$0.1	($18.5)	$31.8	35.5%	$19.1	$0.2	($8.7)	$32.6	32.6%
PECO	$14.0	$0.3	($10.9)	$24.9	13.4%	$6.2	$0.8	($12.0)	$78.0	(6.5%)	$7.7	$0.0	($19.5)	$71.3	(16.5%)
PEPCO	$37.3	$0.0	($8.3)	$20.5	141.9%	$59.2	$0.0	($15.5)	$53.8	81.2%	$82.9	$0.0	($14.5)	$56.7	120.6%
PPL	$43.7	$1.3	($11.5)	$30.8	108.7%	$160.3	$0.0	($21.5)	$103.3	134.4%	$116.0	$0.0	($23.4)	$78.9	117.4%
PSEG	$43.2	$0.4	($13.9)	$25.0	118.4%	$94.0	$0.2	($23.1)	$76.0	93.4%	$42.7	$0.4	($22.2)	$71.6	29.2%
REC	$1.0	$0.0	($0.6)	$2.1	21.0%	$1.1	$0.0	($0.8)	$5.3	6.2%	$0.7	$0.0	($0.8)	$4.4	(1.6%)
Total	$700.9	$11.2	($256.2)	$643.4	70.9%	$1,544.3	$18.8	($457.4)	$1,624.6	68.1%	$1,596.9	$31.0	($420.6)	$1,577.1	76.5%

* First ten months of the 2022/2023 planning period

ARR Allocation and Congestion In and Out of Zone

Table 13-29 shows the share of ARR MW for the first ten months of the 2022/2023 planning period with paths that source inside and outside the zone where the ARR load is located, and the proportion of congestion that results from constraints that are inside and outside the zone. Table 13-29 allows a comparison of externally sourced ARRs with the congestion that results from external constraints. For example, 99.6 percent of ACEC congestion results from constraints that are outside of the zone, but only 31.7 percent of ACEC ARRs originate outside the zone.

Table 13-29 illustrates one of the fundamental issues with the path based approach to ARR/FTR design. In the PJM market, which operates as an integrated network, a significant proportion of congestion results from constraints that are not in the same zone as load, but the assignment of ARRs is inconsistent with that fact. This inconsistency makes it impossible for load to match ARRs with the actual sources of congestion.

Table 13-29 ARR Allocation and Congestion from inside and outside zone: 2022/2023

	ARRs		Congestion	
	Out of Zone	In Zone	Out of Zone	In Zone
ACEC	31.7%	68.3%	99.6%	0.4%
AEP	8.7%	91.3%	94.4%	5.6%
APS	12.6%	87.4%	99.0%	1.0%
ATSI	25.1%	74.9%	99.6%	0.4%
BGE	37.4%	62.6%	92.4%	7.6%
COMED	0.0%	100.0%	95.4%	4.6%
DAY	75.9%	24.1%	99.9%	0.1%
DOM	0.1%	99.9%	94.3%	5.7%
DPL	27.1%	72.9%	75.0%	25.0%
DUKE	34.6%	65.4%	80.7%	19.3%
DUQ	77.7%	22.3%	100.0%	0.0%
EKPC	53.3%	46.7%	99.9%	0.1%
EXT	100.0%	0.0%	90.2%	9.8%
JCPL	17.0%	83.0%	98.7%	1.3%
OVEC	NA	NA	94.9%	5.1%
MEC	41.1%	58.9%	86.2%	13.8%
PE	18.7%	81.3%	89.5%	10.5%
PECO	13.5%	86.5%	97.4%	2.6%
PEPCO	31.6%	68.4%	100.0%	0.0%
PPL	0.1%	99.9%	87.2%	12.8%
PSEG	33.2%	66.8%	99.8%	0.2%
REC	100.0%	0.0%	98.1%	1.9%
Total	17.3%	82.7%	91.8%	8.2%

Credit

There was one collateral default and zero payment defaults in the first three months of 2023.

On December 21, 2021, PJM submitted a change to the credit rules to FERC.[41] Under the proposed rules PJM would replace the current credit calculation, which is largely based on a weighted average historical FTR value, with an initial margin based on a risk confidence interval from an historical simulation (HSIM) analysis model. PJM's proposal included the use of a 97 percent confidence interval, meaning a 97 percent probability that the initial margin collected would cover potential default costs. The MMU recommends the use of a 99 percent confidence interval when calculating the initial margin requirements for FTR market participants, in order to assign the cost of managing risk to the FTR holders who benefit or lose from their FTR positions.[42]

The most fundamental point is that if costs are shifted from FTR buyers to other market participants, no cost-benefit analysis can show that the other market participants benefit in any way. Under the current default rules, the cost of default is socialized to all market participants, not just those participating in the FTR market. The 99 percent confidence interval places more of the risk where it belongs, on the FTR market participant that is engaged in the risky behavior, than the 97 percent confidence interval. The goal of internalizing as much of the risk to the FTR participants as possible, where it belongs, could be more directly addressed either by using 100 percent or by ensuring that the tail risk be borne solely by those in the FTR market rather than all market participants.

On February 28, 2022, FERC rejected PJM's filing recommending a 97 percent confidence interval because the record did not support 97 percent.[43] FERC instituted a Section 206 proceeding, but recognized that PJM could propose revisions through a Section 205 filing. On June 3, 2022, PJM submitted the same change to the credit rules as the December 21, 2021 filing to FERC.[44] The June 3, 2022, filing included a cost benefit analysis for the proposed use of a 97 percent confidence interval compared to the use of a 99 percent confidence interval. The MMU continues to recommend the use of a 99 percent confidence interval when calculating the initial margin requirements for FTR market participants.

On August 2, 2022, FERC accepted and suspended PJM's June 3 filing for a nominal period to become effective August 3, 2022, subject to refund and subject to the outcome of newly established paper hearing procedures.[45]

Default Portfolio Considerations

Under the method applied to the GreenHat default, when an FTR participant defaults on their positions, their portfolio remains in the FTR market and

41 *See* "Revisions to PJM's FTR Credit Requirement and Request for 28-Day Comment Period," Docket No. ER22-000 (December 21, 2021).

42 Comments of the Independent Market Monitor for PJM, Docket No. ER22-2029-000 (June 24, 2022)

43 See 178 FERC ¶ 61,146.

44 *See* "Revisions to PJM's FTR Credit Requirement," Docket No. ER22-2029-000 (June 3, 2022).

45 See 180 FERC ¶ 61,073

continues to accrue revenues and/or charges and must be reconciled. Under this method, PJM leaves the participant's positions unchanged, lets the positions settle at day-ahead prices, and charges any net losses to the default allocation assessment. This method exposes all members in PJM to an uncertain charge for the default allocation assessment that will not be known until those FTRs settle.

The MMU recommends a method under which defaulted FTRs would be canceled rather than holding or liquidating them. Canceling the FTRs would release the FTRs to the FTR market. The market would then decide the value of the capacity released and the timing of its release. There would be no discretion necessary to settle the defaulted position and the losses would be contained within the ARR/FTR market.

Cancellation of a defaulting portfolio does not change congestion. But cancellation of a defaulting portfolio can affect ARR/FTR funding as a result of changes in auction revenue, changes in the net target allocations, and potential simultaneous feasibility violations, while any collateral collected from the defaulted participant is available to offset losses from the cancelled FTRs. However, PJM can and does address similar issues routinely. PJM has tools available, such as the counter flow buyback and Stage 1A over allocation rules, and uses them regularly in the Annual FTR Auction, to improve funding as well as address feasibility concerns. Cancellation of FTRs would isolate the costs of the default to those participating in and benefitting from the FTR market.

FTR Forfeitures

By order issued January 19, 2017, the Commission determined that the FTR forfeiture rule is just and reasonable and "...serves to deter such manipulation" related to virtual transaction cross product manipulation.[46] The Commission identified four main tenets with which the Forfeiture Rule must comply, including that it: deter manipulation, provide transparency allowing participants to modify their behavior, base forfeitures on an individual participant's actions and is not punitive.[47]

46 See 158 FERC ¶ 61,038 at P 33 (2017).
47 See *id.* at P 62.

The point of the FTR forfeiture rule is to avoid an inefficient and costly market power mitigation process and to establish an objective rule that prevents manipulation of the FTR market. The FTR forfeiture rule is designed to remove the incentive to engage in manipulation. The rule does not result in findings of manipulation.[48]

The FTR forfeiture rule considers the impact of a participant's net virtual transaction portfolio on all constraints.[49] If a participant's net virtual portfolio impacts a constraint by the greater of 0.1 MW or 10 percent or more of the constraint line limit, and that constraint affects an individual FTR's target allocation by $0.01 or more, the participant's net virtual portfolio increased the value of the FTR, and the FTR is subject to FTR forfeiture. The FTR forfeiture also requires that congestion on the FTR path in the day ahead market be greater than congestion on that path in the real time market.

The FTR forfeiture rule does not require FTR holders to pay penalties. The FTR forfeiture rule does not affect the profits or losses of virtual activity. The FTR forfeiture rule, if triggered by a participant's virtual portfolio, results in forfeiting only FTR profits and only in the specific hours for which the rule is violated. The profit is calculated as the hourly FTR target allocation minus the FTR's hourly cost. Even when FTR profits are forfeited, the value that the buyer assigned to congestion in the FTR auction (the price paid) is not affected. For example, if a buyer paid $5.00/MWh for congestion and congestion was $5.00/MWh, the forfeiture would be zero. If congestion were $7.00/MWh, the forfeiture would be $2.00/MWh. Market participants understand the relationship between FTR and virtual positions in detail and can avoid violating the FTR forfeiture rule if they choose to do so.

The FTR forfeiture rule is less effective than initially intended as a result of the element of the rule requiring that day-ahead congestion on the FTR path be greater than real-time congestion the same path. As a result of model differences, there is a significant opportunity for virtual participants to profit from differences between day-ahead and real-time prices without driving the

48 *See* "Protest and Motion for Rejection of the Independent Market Monitor for PJM," Docket No. EL20-41 (June 1, 2020).
49 A modified FTR forfeiture rule was implemented effective January 19, 2017. See *2019 State of the Market Report for PJM*, Volume II, Section 13: Financial Transmission Rights for the full history.

prices together, termed false arbitrage. As a result, FTR holders can use virtual positions to make their FTR positions more valuable without violating the rule.

The FTR forfeiture rule has not reduced participation in the PJM FTR market or participation in virtual activity. There has been an increase in the number of participants in the FTR market since the implementation of the new FTR forfeiture rule, and a decrease in the number of participants with forfeitures.

On June 24, 2019, PJM implemented a new method to calculate the hourly cost of an FTR only for hours in which it is effective.[50] Beginning with the September 2019 bill, PJM began billing using the correct hourly cost calculation. For the 2020/2021 planning period, total FTR forfeitures were $4.6 million.

On May 20, 2021, FERC issued an order ruling the $0.01 definition of an increase in the value of an FTR unjust and unreasonable, but upheld the other parts of PJM's forfeiture rule.[51] In this order, FERC required PJM to modify the FTR forfeiture rule and submit a compliance filing. As a result, there was no FTR forfeiture rule in place from May 21, 2021 until February 1, 2022. These months have zero forfeiture in Figure 13-14.

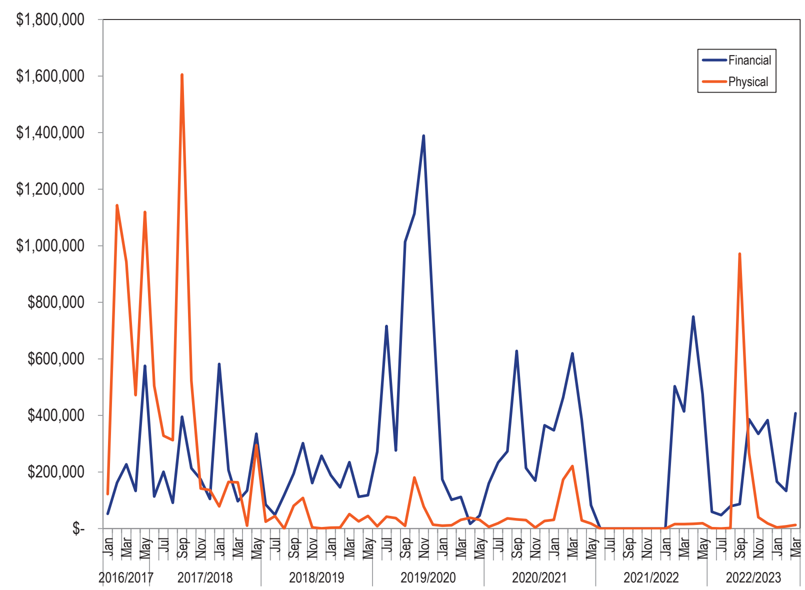
On June 21, 2021, PJM filed a request for clarification, or alternatively rehearing.[52] PJM asked that FERC clarify the status of the forfeitures that were assessed over the four years between the initial FERC order for a compliance filing, and their order rejecting PJM's compliance filing. On July 19, 2021, PJM made a compliance filing to address FERC's concerns with the $0.01 element of the FTR forfeiture rule.[53] PJM's compliance filing eliminated that element and replaced it with a constraint based FTR forfeiture. The forfeiture is based on the increased value of each constraint that violates the rule, determined by the shadow price multiplied by the net dfax on that constraint. This change meets FERC's previously established criteria established under the initial FERC order and creates a more precise FTR forfeiture value, to meet the criteria established under the new FERC order.

50 *See* "Minor modification to Tariff Language for FTR Forfeiture Rule," Docket No. ER19-2240 (June 24, 2019).
51 See 175 FERC ¶ 61,137 (2021).
52 See Request for Clarification or, in the Alternative, Rehearing of PJM Interconnection, LLC, FERC Docket No. ER17-1433-000 (June 21, 2021).
53 *See* "FTR Forfeiture Rule Compliance Filing," FERC Docket No. ER17-1433 (July 19, 2021).

On January 31, 2022, FERC accepted PJM's July 19, 2021 compliance filing to implement FTR forfeitures using a constraint based method, effective February 1, 2022.[54]

Figure 13-14 shows the monthly FTR forfeitures under the modified FTR forfeiture rule from January 19, 2017, through March 31, 2023. As required by the FERC order, PJM began retroactively billing FTR forfeitures with the September 2017 bill. In the period from January 2017 through September 2017, participants did not have good information about the level of their FTR forfeitures, so they could not accurately modify their bidding behavior to avoid FTR forfeitures. After September 2017, FTR forfeitures decreased significantly, and stabilized, as participants received information on their FTR forfeitures. Calculations of forfeitures under the new constraint specific rule from February 1, 2022, through March 31, 2023, are included in Figure 13-14.

Figure 13-14 Monthly FTR forfeitures for physical and financial participants: January 2026 through March 2023



54 See 178 FERC ¶ 61,079.