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]

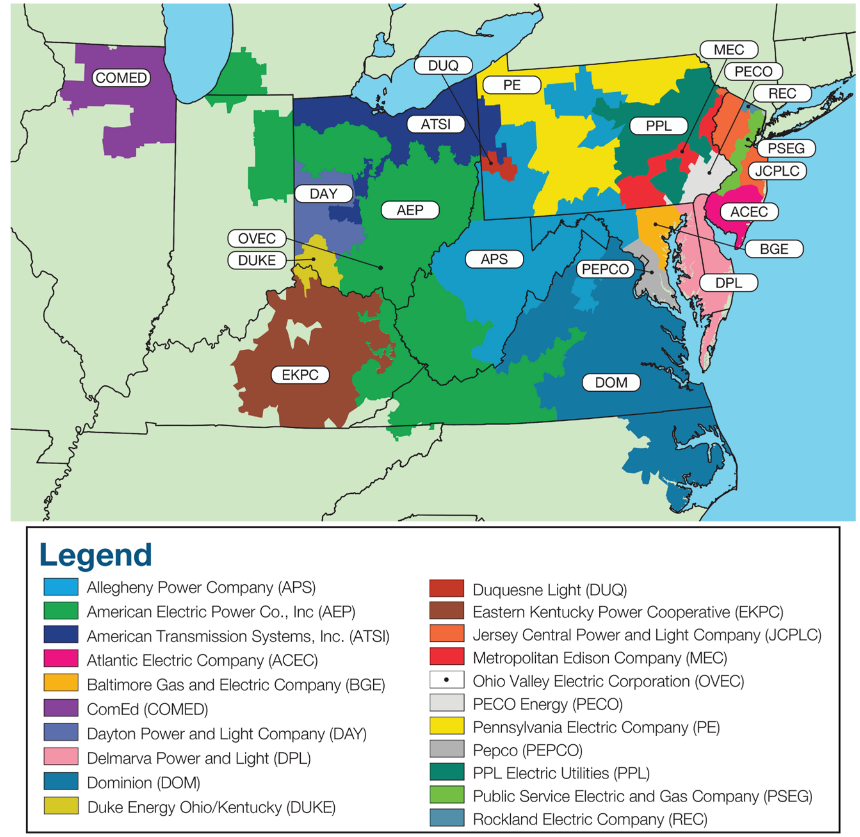
	(Jan-Mar) 2022	(Jan-Mar) 2023	Percent Change
Average Hourly Load Plus Exports (MWh)	98,417	93,209	(5.3%)
Average Hourly Generation Plus Imports (MWh)	100,535	94,971	(5.5%)
Peak Load Plus Export (MWh)	130,779	123,504	(5.6%)
Installed Capacity at March 31 (MW)	185,769	183,312	(1.3%)
Load Weighted Average 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.

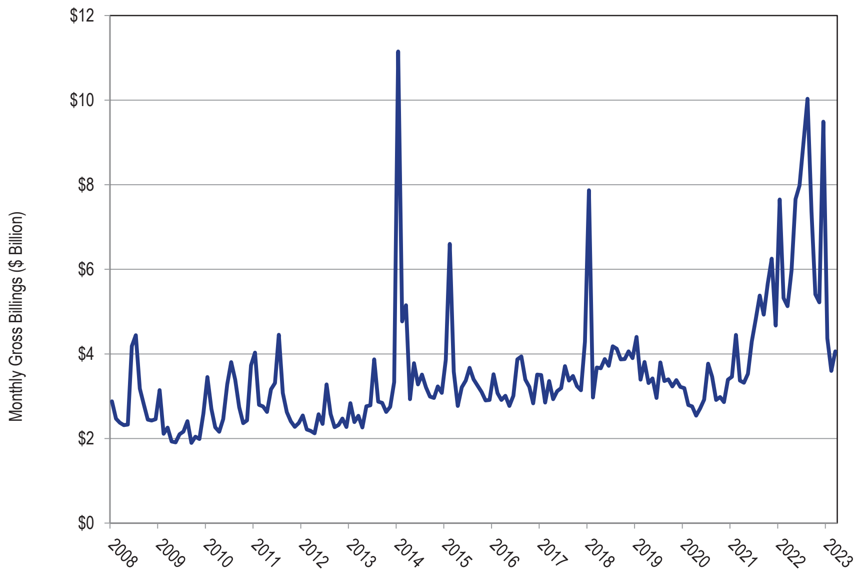
Figure 1-1 PJM's footprint and its 21 control zones



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]

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

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.

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]

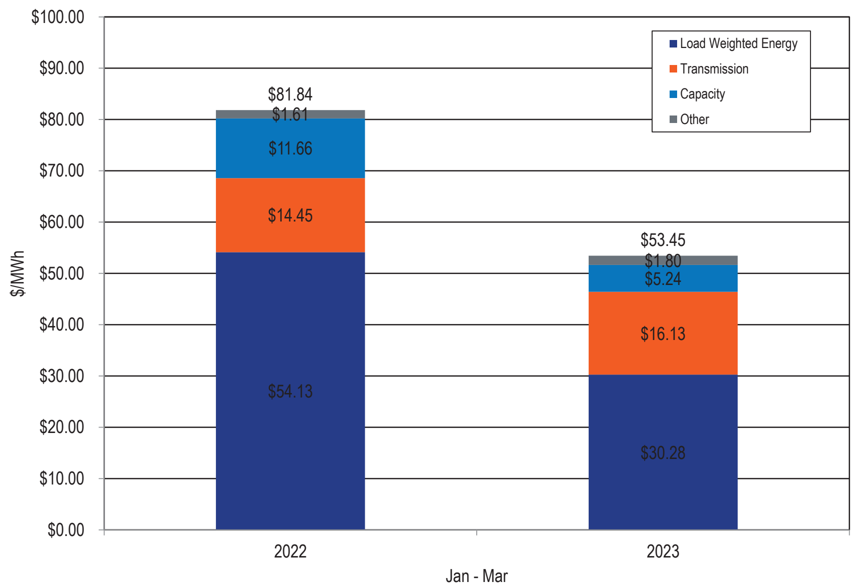
Table 1-9 Inflation adjusted total price per MWh by category: January through March, 2022 and 2023[64 65]

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.)
- 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

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).

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.

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.

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

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.

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

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).

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.

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.

- 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

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.)

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.)

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

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.