Response to the
2018 State of the Market Report

May 6, 2019

PJM Interconnection

This page is intentionally left blank.

Contents

Executive Summary

This document presents PJM Interconnection's response to the 2018 State of the Market Report for PJM[1] issued by the PJM Independent Market Monitor, Monitoring Analytics, LLC (IMM). Each year, in its annual State of the Market Report, the IMM provides an independent assessment of market performance, offering valuable conclusions and recommendations aimed at enhancing PJM's markets.

In the 2018 State of the Market Report (2018 SOM), the IMM concludes that the results of the PJM Energy, Regulation, Synchronized Reserve, Day-Ahead Scheduling Reserve and Financial Transmission Rights (FTR) Markets produced competitive results but that the Reliability Pricing Model (RPM or capacity market) results were not competitive. PJM agrees with the IMM's conclusions regarding the competitiveness of the PJM market results with the exception of the capacity market. In that regard, PJM believes that the IMM's conclusion lacks appropriate support. Nevertheless, PJM believes that the capacity market can benefit from new aggregate market-power mitigation measures.

This report is organized into two main sections. The first section provides a broad PJM view of the state of the market, covering three topics: (1) setting the stage and market design principles; (2) key developments in 2018; and (3) market resilience and moving forward. The second section provides PJM's response to recommendations contained in the 2018 SOM that have been identified by PJM for action or assessment.

Report Highlights

1. For more than 20 years, PJM market results have consistently produced competitive results, a good indication that the underlying bid-based security-constrained market design is fundamentally sound.
2. PJM agrees with the 2018 SOM conclusions regarding the competitiveness of the PJM markets except for the capacity market, for which PJM believes that the IMM's conclusion lacks appropriate support.
3. Key developments in 2018 include energy price formation proposals on fast-start pricing and reserve pricing, proposed changes to the capacity market and changes in the FTR market.
4. PJM is investigating new aggregate market-power mitigation measures and developing risk evaluation methods to improve incentive performance and lower entry barriers for competitive resources.
5. PJM has initiated an expedited stakeholder effort to consider rule changes addressing financial risk management in the PJM markets.
6. Moving forward, PJM will continue to address ongoing challenges with the goal of enhancing the transparency and resilience of PJM's market design.

[1] 2018 State of the Market Report for PJM: Volume 2 Detailed Analysis, March 14, 2018, at https://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2018/2018-som-pjm-volume2.pdf

Introduction

Setting the Stage

Over the past 20 years, PJM's markets have delivered competitive results, maintaining system reliability, keeping system costs low and attracting new entry in ways that foster innovation and yield environmental benefits. Since 1999, the PJM markets have been producing stable fuel-adjusted energy prices as illustrated Figure 1. Moreover, as illustrated in Figure 2, since 2007, the PJM market has attracted 37 GW of new resources.

Figure 1. Load-Weighted LMP and Fuel-Cost Adjusted LMP

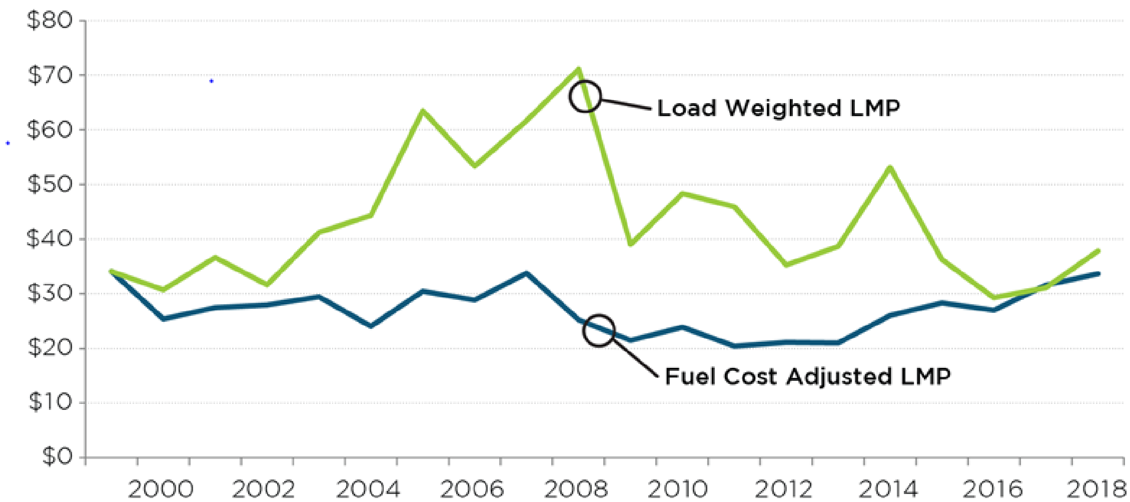


Figure 2. New Generation in Capacity Auction and in Service

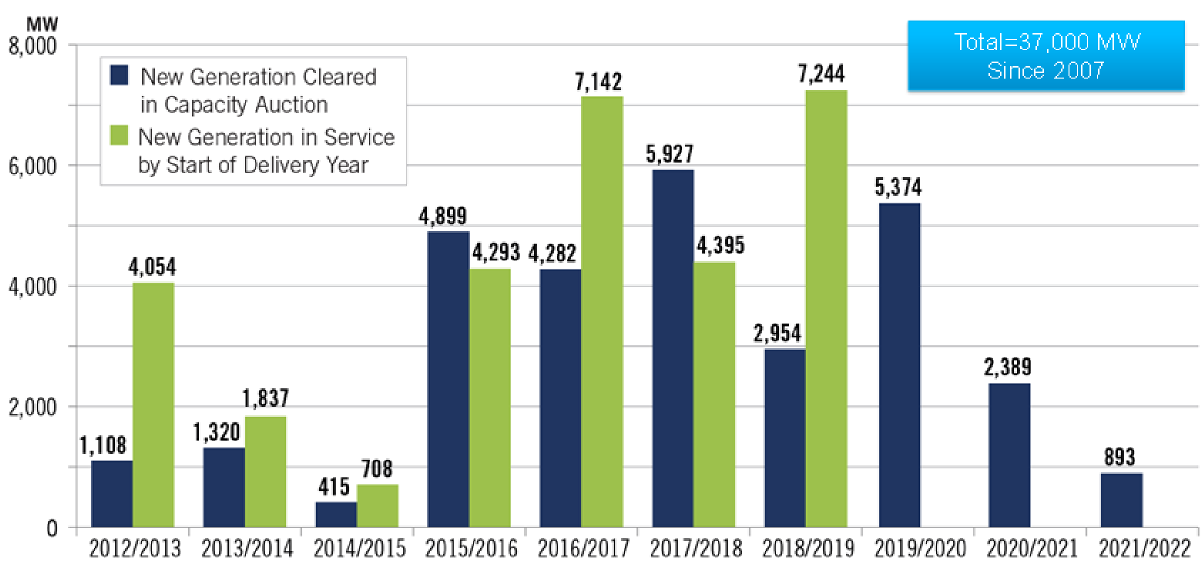
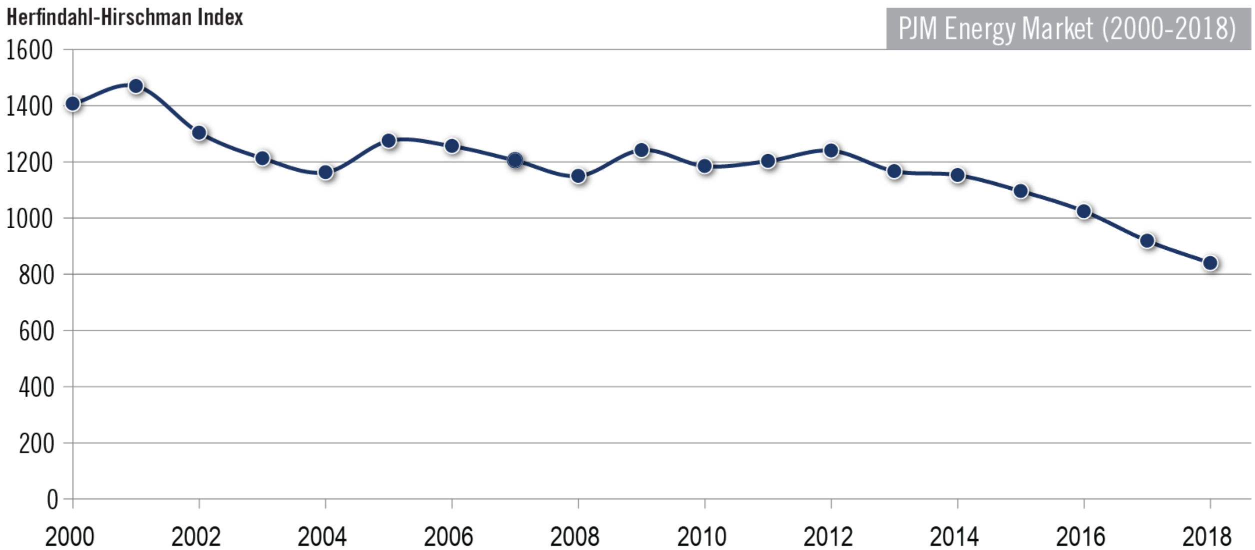


Figure 3 shows the trend of the Herfindahl-Hirschman Index (HHI), a market concentration index, from 2000 to 2018.[2] FERC has adopted HHI as an indicative measure of horizontal market power with a threshold of 1,000, below which the market is deemed competitive.[3] Figure 3 indicates that the competitiveness of PJM's Energy Market has improved since 2000, and for the first time, the HHI fell below the 1000 level in 2017–2018.

Figure 3. PJM Energy Market HHI



Source: PJM State of Market Reports 2000 – 2018, PJM and Market Monitoring Analytics

The competitive market results provide a good indication that the underlying bid-based security-constrained market design is fundamentally sound. A natural question is: If the market design is sound, why is market reform needed?

Is it because:

1. The industry has been changing rapidly, so the market needs to adapt?
2. New technologies have caused disruptive shifts, so the market needs to accommodate them?
3. The discovery of shale gas, the penetration of renewables and the slow demand growth have changed the underlying economics, so the market needs to recalibrate?
4. State subsidies are threatening, so the market needs to respond with alternatives?

These questions have been raised and vigorously discussed in the stakeholder process. However, in the end, they all led to one simple question: Are the markets producing right prices?

In 2018, PJM focused on long-standing price formation issues comprehensively, including the energy, reserve, capacity, and FTR markets, to enhance market performance without further delay. Moving forward, PJM will continue to address ongoing challenges in an increasingly complex environment, enhancing the transparency and resilience of market design.

---

[2] The Herfindahl-Hirschman Index (HHI) is a widely used measure of market concentration. It is calculated by squaring the market share of each firm competing in a market and then summing the resulting numbers. It is a dimensionless and can range from close to zero to 10,000. The HHI is a useful indicative measure though not a conclusive indicator of market power in wholesale electricity markets. The metric does not account for forward contracts for generator output that may reduce the level of market power, and it ignores the effect that transmission constraints can have on the local market or load pockets that result from these constraints. These limitations notwithstanding, HHI is easy to calculate and simple to understand.

[3] FERC (2011) "Analysis of Horizontal Market Power under the Federal Power Act," Docket No. RM11-14-000, March 17.

Market Design Principles

For more than 20 years, the LMP method has served wholesale electricity markets successfully. However, there have always been circumstances where the prices could not reflect everything relevant to sending the right market signals.[4] The current market design has proven a valuable tool, but it is not a panacea. To meet future challenges within an increasingly complex environment, the market is expected to continue to evolve based on sound principles with improved transparency and resilience.

The foundation of electricity market design and pricing mechanism has been built on the general market equilibrium theory in economics, which provides a principled framework for how the price system works to achieve efficient market allocation that maximizes the social welfare.[5] Fundamental theorems of welfare economics indicate that competitive markets achieve efficient market under "convex conditions." Under convex conditions, the average cost (as well as the incremental cost) of production does not decline when a generating unit's output increases and does not rise when a generating unit's output decreases.

Under convex conditions, the last-cleared unit is always the highest-ranking unit with the highest cost in the merit order. An inflexible generating unit with a significant minimum operational limit, for example, fails the convex condition because when the output decreases below the minimum operational limit, the cost rises, making it uneconomical to run the unit in that range.[6] Under the convex condition, market prices would equate marginal costs and marginal benefits at competitive equilibrium, while each consumer's surplus and each producer's surplus is maximized to attain the maximum market surplus. The pricing mechanism plays the essential role of the Arrovian "invisible hand," which ensures efficient market performance with three essential principles:[7]

1. First, the right price signals reflect the costs and scarcity values accurately.
2. Second, individual buyers and sellers would have self-motivated incentives to provide truthful bids and follow operator instructions to attain competitive equilibrium. This principle is known as incentive compatibility.
3. Third, the market revenue should be sufficient to recover cost for new entry in ways that ensure resource adequacy at lowest costs.

However, under non-convex conditions, it is theoretically impossible to fulfill these three principles simultaneously.

The developments of game theory and auction design have laid the theoretical foundation of market mechanism design. In particular, the innovative Vickrey auction design, with its signature feature of separating the selection (first-best) and the

[4] See PJM (2017), Proposed Enhancements to Energy Price Formation, PJM Interconnection LLC, November 15, 2017. Retrieved from http://www.pjm.com/-/media/library/reports-notices/special-reports/20171115-proposed-enhancements-to-energy-price-formation.ashx

[5] In the day-ahead and real-time energy markets, the social welfare function is represented by the market surplus.

[6] In electricity markets, non-convexity arises for other technical reasons, such as fixed start-up/no-load costs, economies of scale and inflexibilities such as minimum-generation or block-loading requirements. Under non-convex conditions, units that are economically selected to serve load may incur losses if the price is set at marginal cost.

[7] As is well known, Adam Smith created the famous metaphor of "invisible hand" with the conjecture that the invisible hand will guide efficient exchange of scarce resources through competition in the marketplace. Later, Stanford University Professor Kenneth J. Arrow, a winner of Economics Nobel Prize in 1972, offered fundamental insights in social choice theory laying the foundation for fundamental theorems of welfare economics setting out the precise conditions under which the "invisible hand" conjecture holds true so that the general competitive equilibrium can achieve efficient outcome and maximize social welfare. One of the necessary conditions is known as convex preferences and production sets for consumers and producers. Professor Arrow and his students further developed the concept of quasi-equilibrium under non-convex conditions restoring the incentive compatibility property in competitive markets as the number of agents increases arbitrarily large.

pricing (second-best) rules in auction design, lays the foundation for studying incentives for market mechanisms. The development of the homeostatic control theory in the 1980s laid the theoretical foundation for integrating marginal-cost pricing principles into system control of the electric grid based on locational marginal pricing (LMP).[8] In 1997, PJM developed market rules that embody these market design principles. At the time, for practicality, the current LMP-based pricing mechanism was adopted as a reasonable approximation of efficient pricing. For more than 20 years, it has been accepted by regulators as a just and reasonable pricing method. Also, at the time of electricity restructuring, many important market design issues called for attention in public policy and academic forums, including the bidding format. With a three-part cost structure of variable, no-load and start-up costs, the three-part bid format includes variable energy and fixed commitment costs. While a one-part bid format was generally considered simpler and more compatible with the marginal-cost pricing principle, the three-part bid format provides useful information to the system operator for making efficient allocation decisions for economic commitment and dispatch in pool-based markets. But a three-part bid structure creates non-convexity issues that complicate the design of the pricing mechanism.

By ignoring commitment costs that cause non-convexity, the current LMP method is not incentive compatible. For example, it has been observed that a significant number of combustion turbines scheduled their daily bids in unit parameters, which are less flexible than the original equipment manufacturer data, while units are not rewarded for offering flexibility to the market. Such incentive may exacerbate market power behavior in the presence of local transmission constraints. Some units have an incentive to offer in a manner that maximizes a potential uplift payment (for example, by claiming a longer minimum run time). Although such bidding behavior may be rational from the perspective of each individual supplier, collectively, it could cause distorted price formation.[9]

Scarcity pricing is another important concept in economics pertinent to efficient price formation.[10] Scarcity pricing and shortage pricing are closely related concepts for energy price formation. They have often been used interchangeably, as in the State of Market reports and some of the FERC staff reports. Below we highlight a distinction between scarcity pricing and shortage pricing for it makes an important difference in the context of the reserve pricing reform.

As Figure 4 shows, one of the simplest ways to implement and understand scarcity pricing in the Energy Market is to put demand response back on the demand side. The left-side diagram in the figure shows an upward-sloping supply curve that becomes a vertical line when it reaches the capacity limit G1. This representation is consistent with the merit order dispatch of units ranked in increasing short-run marginal costs. The demand curve is shown as a downward sloping curve as dictated by the law of demand. The diagram shows how the demand and the supply curves intersect to set the market-clearing price at P1. Scarcity pricing refers to the situation in which the generation supply is at the capacity limit, and the price is set by the demand curve at a level above the marginal cost (MC) on the supply curve. The difference between the market price and the marginal cost, P1 - MC, equals the scarcity rent. At PJM, the uncovered scarcity rent in the Energy Market is currently provided through the capacity market.

[8] Hogan, W. W. (1992) 'Contract networks for electric power transmission', Journal of Regulatory Economics, 4(3).

[9] Chao, H. (2018) Challenges for Getting the Prices Right in PJM's Wholesale Electricity Markets, Harvard Energy Policy Seminar, March 26. Retrieved from https://sites.hks.harvard.edu/m-rcbg/cepr/HKS%20Energy%20Policy%20Seminar%20-%20Chao%2020180326.pdf . Chao, H. (2019) Electricity market reform to enhance the energy and reserve pricing mechanism: Observations from PJM, Energy Systems Workshop at Isaac Newton Institute, University of Cambridge, January 7, 2019. Retrieved from http://www.newton.ac.uk/files/seminar/20190107160017001-1481148.pdf .

[10] Indeed, scarcity is one of the most basic concepts in economics. Simply put, economics is the study of how people make choices under conditions of scarcity. Without scarcity, economics will never be the same.

In Figure 4, the right-side diagram shows that during an unanticipated shortage event, all the available generation capacity G2 is utilized and demand is price-inelastic. As a result, load curtailment occurs, by an amount L2 - G2. In such a contingency, the demand and supply curves become parallel vertical lines, and shortage price is set by an administratively determined estimate of the value of lost load (VOLL). For example, in ERCOT (Electric Reliability Council of Texas), the VOLL is set at $9,000 per MWh. In the PJM market, no estimate has been made of the value of lost load. Instead, during a shortage event, the price may be set by the offer cap at $2,000 per MWh or the reserve penalty-factor adder at $850 per MWh.

Figure 4. Scarcity and Shortage Pricing in the Energy Market

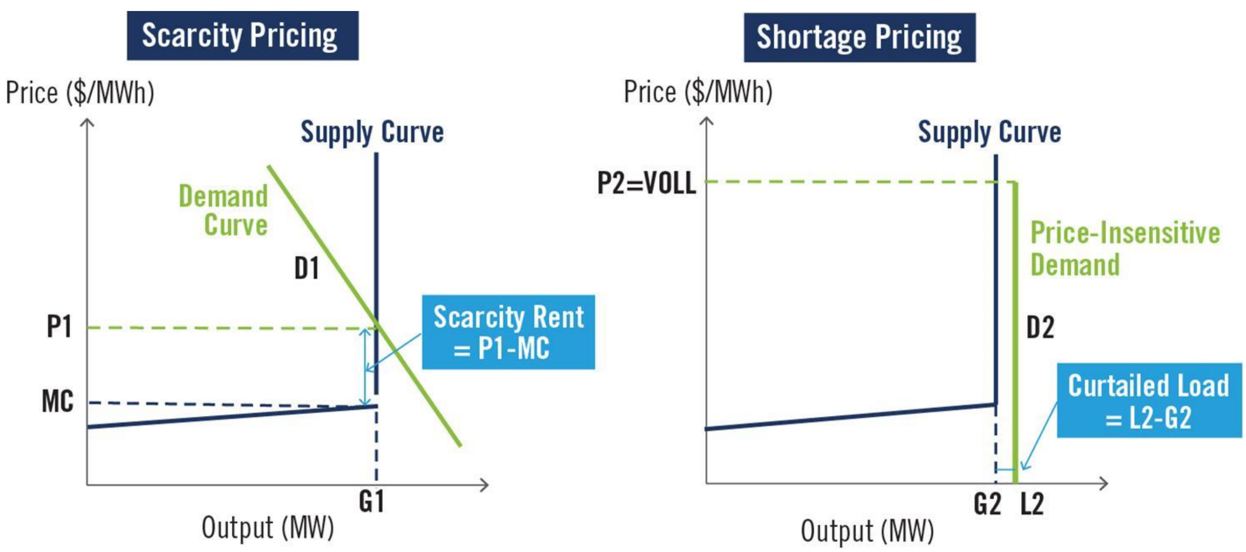


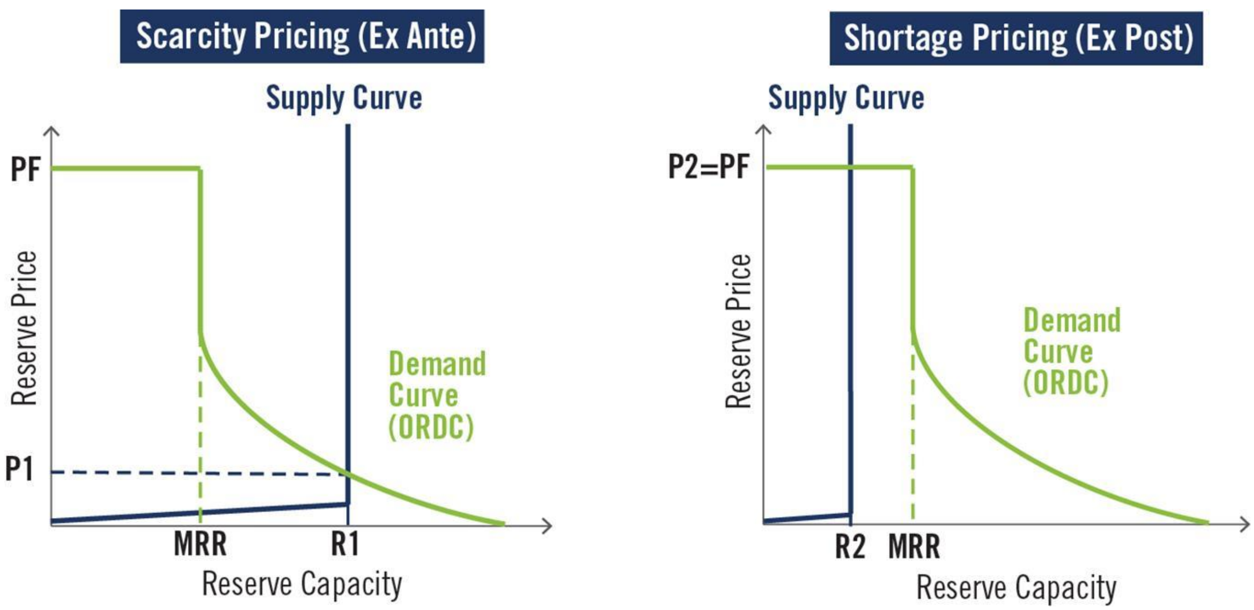
Figure 5 illustrates the concepts of scarcity pricing and shortage pricing for operating reserves. Operating reserves are an ancillary service to assist the system operator in managing short-term operational uncertainty. Reserve pricing involves two different time frames in which scarcity pricing is applied *ex ante* to the normal period before a shortage period and shortage pricing is applied *ex post* to an emergency period during a shortage event.

This pricing structure is similar to an insurance contract with insurance premium paid in advance and uncertain insurance compensation paid only in the event of a contingency. These payments are structured in two separate time frames under different conditions. Paying an insurance premium makes sense even if the contingency for which one is insured against never occurs.

In Figure 5, the left-side diagram illustrates scarcity pricing for reserve in normal periods, when the available reserve capacity is above the minimum reserve requirement (MRR). The operating reserve demand curve (ORDC) is based on the conditional expectation of the reserve shortage penalty factor during a shortage event, when the reserve capacity level falls below MRR. In the absence of sufficient price-elastic demand bidding in the Energy Market, the ORDC serves as a proxy for demand bidding in the Reserve Market. The right-side diagram of Figure 5 shows how shortage pricing works when the available reserve capacity falls below the MRR level, and emergency procedures are triggered. In normal periods, scarcity pricing incent flexible resources to be available to provide reserves. In the event of an emergency, shortage pricing incent these resources to perform to avoid outages. On one hand, in energy pricing, scarcity pricing and shortage pricing are interchangeable concepts like substitutes. On the other hand, in reserve pricing, scarcity pricing and shortage pricing are distinct complements that must be joined in order to produce efficient incentives.

Obviously, the above illustrations of scarcity pricing and shortage pricing is based on some simplified assumptions but the conclusion that scarcity pricing and shortage pricing are essential, distinctive and complementary elements in the energy and reserve price formation remains true even in more complicated situations, an important factor in market design that has sometimes been overlooked. Moreover, the Energy and Reserve Markets are recurrent and interact dynamically on a transmission network, and locational congestion pricing, in itself, is a form of scarcity pricing. Through co-optimization, reserve pricing reform will benefit Day-Ahead as well as Real-Time Energy and Reserve Markets.

Figure 5. Scarcity and Shortage Pricing in the Reserve Market



The capacity market is fundamentally different from the Energy Market. While the Energy Market is for actually producing electricity and maintaining reliability, the capacity market is a market for entry to ensure resource adequacy. The purpose of reserve pricing is not to replace the capacity market. The implementation of reserve pricing is expected to result in a new market equilibrium that will cause some relatively modest shifts of revenues between the energy, reserve and capacity markets. Nonetheless, the aggregate costs to customers should remain stable and be reduced as market efficiency improves in the long term. From a broad perspective, in addition to improving overall market performance, reserve pricing reform is also expected to reduce uplift payments and improve market transparency in the near term.

Key Developments in 2018

This subsection highlights key developments in 2018 concerning Energy and reserve price formation proposals, capacity market and subsidies, financial transmission rights and market resilience.

Energy Price Formation

In 2016, the Federal Energy Regulatory Commission (FERC) issued Notices of Proposed Rulemaking and orders to enhance energy price formation. In 2017, PJM responded to the energy price formation issues. With stakeholder approval, on December 21, 2017, PJM launched an energy price formation initiative for improving the LMP calculation, scarcity pricing and shortage pricing in Energy and Reserve Markets. PJM has presented two categories of proposals regarding how prices are formed in the Energy and Reserve Markets.

The first category deals with how the LMP is calculated in the Energy Market. Building on the extended LMP (or convex-hull pricing) approach, PJM's proposal leaves existing dispatch processes in place but would add a separate pricing run intended to optimize prices and their incentive effects. That separate pricing run would use a mathematical technique called "integer relaxation" to allow prices to reflect the commitment costs needed to serve real-time load and relax the economic minimum level of all resources. The PJM proposal would ensure efficiency of the Energy Market, maximizing the market or social surplus in the commitment and dispatch process. Through a separate pricing run, the PJM proposal would produce market prices that accurately reflect costs and scarcity values that support an efficient commitment and dispatch solution. This pricing run would reduce uplift payments and promote efficient market results. Enhanced energy price formation would enable a more effective "invisible hand" that incents flexibility in ways that are neutral to fuel sources and technologies.

Fast-Start Pricing

On December 21, 2017, the FERC issued a 206 Order on pricing reform for "fast-start" resources because PJM's existing Real-Time Energy Market clearing process for fast-start resources was inconsistent with the cost-minimizing dispatch solution, and its fast-start pricing does not allow prices to accurately reflect the marginal cost of serving load.[11] On February 12, 2018, PJM filed with the FERC the proposal on fast start pricing reform in the Energy Market. The PJM proposal addresses the price formation issues associated with non-convexity caused by the fixed commitment costs in ways that improve market efficiency, incentive compatibility and revenue sufficiency. Below are key features of the PJM proposal:

1. Fast-start pricing will be implemented with the integer relaxation approach using separate dispatch and pricing runs.
2. The energy prices will reflect the commitment costs (i.e., start-up and no-load) for fast-start resources.
3. The fast-start resources, as applied to the PJM footprint, are defined as resources with start-up and minimum run times of two hours or less.
4. Flexible resources that are dispatched down around inflexible fast-start resources receive lost-opportunity cost credits.

On April 18, 2019, FERC issued its order accepting the PJM proposal on fast start pricing for the most part with the exception that the definition of fast-start resources is limited to units with start-up and minimum run times of one hour or less.[12]

Reserve Pricing Reform

The second category deals with how reserves are procured and priced in the Day-Ahead and Real-Time markets. PJM believes that co-optimized Energy and Reserve Markets with operating reserve demand curves (ORDCs) are critical for Energy and reserve price formation. Co-optimized Energy and Reserve Markets provide the foundation that promotes system reliability.

[11] PJM Interconnection, L.L.C., Order Instituting Section 206 Proceeding and Commencing Paper Hearing Procedures and Establishing Refund Effective Date, Docket No. EL18-34-000 (Dec. 21, 2017) ("206 Order") This proceeding was noticed in the Federal Register on December 28, 2017. 82 Fed. Reg. 61,562 (Dec. 28, 2017).

[12] *PJM Interconnection, L.L.C.,* 167 FERC ¶ 61,058 (Apr. 18, 2019). FERC accepted the above aspects of PJM's proposal with the exception of the definition of fast-start resources. FERC is requiring PJM to define fast-start resources as those with start-up and minimum run times of one hour or less.

Following a Board letter on April 11, 2018, to PJM stakeholders requesting that the Energy Price Formation Senior Task Force (EPFSTF) refocus the task on the issue of reserve procurement and pricing including the operating reserve demand curve (ORDC) construct, the EPFSTF discussed several proposals for comprehensive Reserve Market reform. After nine months of stakeholder discussion, no consensus was reached. Based on the Board's direction, PJM filed a reserve pricing proposal on March 29, 2019, under Section 206 of the Federal Power Act, including the following components in a comprehensive package.

1. Consolidation of Tier-1 and Tier-2 synchronized reserve products
2. Improved utilization of existing capability for locational reserve needs
3. Alignment of market-based reserve products in Day-Ahead and Real-Time Energy Markets
4. ORDCs for all reserve products
5. Increasing penalty factors to ORDCs to ensure utilization of all supply prior to reserve shortages

PJM believes that the proposed changes will improve scarcity and shortage pricing for reserves so that prices could more accurately reflect the value of reliability and flexibility.

Capacity Market and Subsidies

In 2017, with active stakeholder participation, the Capacity Construct and Public Policy Senior Task Force (CCPPSTF) conducted about eight months of discussion on the issues of state subsidies potentially compromising the integrity and effectiveness of the capacity market to promote efficient entry and exit. In April 2018, PJM submitted a filing with FERC with two proposals. While FERC did not accept PJM's proposals as submitted, in June 2018, FERC issued an Order initiating a proceeding and paper hearing procedure to address these state subsidy issues. The Order determined that PJM's existing minimum offer price rule (MOPR) was inadequate to address the effects caused by state subsidies.

While FERC suggested a resource carve-out (RCO) option (which would allow resources receiving state subsidies to elect not to participate in the PJM-administered capacity auction, but instead receive a commitment outside of the auction), PJM included in its filing an extended RCO because the RCO option alone would not effectively address the price-suppressive impacts of state subsidies. With extended RCO, the competitive capacity market clearing price is determined in a way that avoids the price suppression effects caused by uneconomic resources that elect the RCO option. For offers in the auction that are economic but are displaced by the uneconomic RCO resources, PJM's proposal is to compensate these offers their infra-marginal rent portion of the market-clearing price in such a way that is incentive-compatible with competitive bidding behavior. PJM believes that the proposed changes would accommodate the state policies in ways that are supported by the beneficiary-pays principle. PJM's capacity market reform proposal was filed with FERC on October 2, 2018, and is pending.

State subsidies for uneconomic nuclear generating resources present unique challenges to PJM's market design. Subsidies are broadly recognized as an ineffective policy instrument to achieve policy goals for dealing with negative externalities such as achieving emission reduction objectives. Subsidies, if not mitigated, distort electricity price signals and shift investment risk to consumers. In addition, subsidies beget further subsidies. In effect, subsidies tend to suppress market prices and spread the financial stresses that triggered subsidies in the first place.[13] If reductions in carbon emissions are the goal of policy-makers, then pricing carbon as the externality would be a more effective and efficient

[13] Blumsack, S., C. Lo Prete, U. Shanbhag, and M. Webster (2018) Analysis of State Policies Interactions with Electricity Markets in the Context of Uneconomic Existing Resources: A Critical Assessment of the Literature, Pennsylvania State University, 2018.

mechanism to achieve this policy goal. To be clear, PJM does not endorse or advocate for any particular policy position. However, while subsidies to maintain otherwise uneconomic resources in operation are damaging to the long-term ability for markets to achieve their goal of reliability at the lowest reasonable cost, pricing externalities such as carbon would allow competitive markets to elicit the most efficient set of resources to maintain reliability while simultaneously achieving a policy goal such as carbon emission reductions.

Financial Transmission Rights

Following the landmark FERC Orders 888 and 889 establishing open transmission access in the electricity sector, the concept of a financial transmission right (FTR) was introduced as a critical element in the wholesale power-market design to serve as the financial equivalent of physical transmission service providing congestion hedging that lowers barriers for market entry.[14,15] The FTR market is key to support the provision of a locational price reference for congestion hedging in the context of LMP and to support forward contracting (including self-supply and bilateral transactions). In turn, forward contracting improves the competitiveness of the Day-Ahead and Real-Time markets. Introduced in 2003, the auction revenue right (ARR) supplements the FTR market because an ARR entitles the holder to receive the revenues from the annual FTR auction or collect congestion revenues through self-scheduling the ARRs into FTRs. The FTR/ARR construct allows market participants to hedge their exposure to the short-term locational price differences by forming bilateral contracts.

On March 30, 2018, PJM filed with FERC a proposal to allocate the surplus day-ahead congestion charges and the surplus FTR auction revenues to ARR holders instead of FTR holders among other administrative changes. On May 31, 2018, FERC issued an order accepting PJM's proposal as filed.[16] PJM believes that these changes strengthen the role of the FTR as a financial hedge tool in ways that will enhance market competitiveness and improve market transparency.

The FTR market presents unique challenges for market participants in managing the financial risk exposures of their market portfolios in ways that account for the changing correlation among resources across the interconnected power grid. PJM believes that there is potential to improve the FTR/ARR design and continues to work with the Independent Market Monitor (IMM) on pursuing enhancements to these markets. Additionally, with unprecedented shifts in resources and an accelerating penetration of distributed resources, new risk evaluation methods may be needed to manage financial risks in the PJM markets. In response to the GreenHat Energy, LLC default in PJM's FTR market on June 21, 2018,[17] PJM has initiated an expedited stakeholder effort to consider market design changes that may be needed to address financial risk management in PJM's markets.

---

[14] In 2005, Congress amended the FPA, adding Section 2175 through the 2005 Energy Policy Act to include, as relevant here, provisions to ensure native load service obligations of Load Serving Entities (LSEs) were adequately protected through allocation of firm transmission rights or equivalent tradable or financial transmission rights to such LSEs. (Energy Policy Act of 2005, Pub. L. No. 109-58, §1233, 119 Stat. 957, 2005).

[15] FERC ORDER on Rehearing and Compliance, January 31, 2017 http://www.pjm.com/directory/etariff/FercOrders/2048/20170131-el16-6-002,%20003,er16-121-001.pdf.

[16] *PJM Interconnection, L.L.C.,* 163 FERC ¶ 61,165 (2018). The Commission also accepted the minor compliance filing it had required for PJM to fix what was a typographical error in the tariff language we submitted in the initial filing.

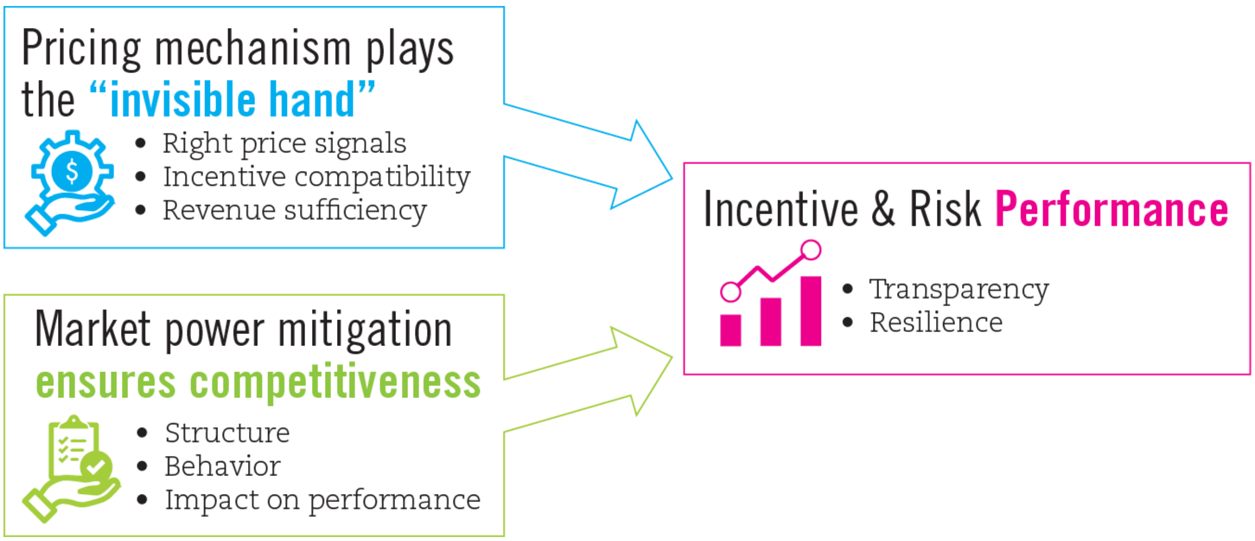
[17] The Report of the Independent Committee of Consultants to the PJM Board https://www.pjm.com/-/media/library/reports-notices/special-reports/2019/report-of-the-independent-consultants-on-the-greenhat-default.ashx?la=en.

Market Resilience

Resilient Market Design

A resilient market design integrates the perspectives of price formation and market power mitigation as shown in Figure 6. On one hand, the pricing mechanism plays the "invisible hand" that fosters economic efficiency through right price signals, compatible incentives, and revenue sufficiency. Efficient prices that reflect actual costs and scarcities are essential to ensure the lowest cost. Incentive compatibility is essential to ensure market behavior consistent with reliability. Revenue sufficiency is essential to ensure competitive entry and exit. On the other hand, market-power mitigation ensures competitiveness through the "visible hand" of structural, conduct and impact measures.

Figure 6. Resilient Market Design Framework



Beyond a competitive and efficient market outcome, a transparent and resilient market design is essential to ensure the enhanced value of competitive markets.

Market power mitigation is important, as it has long been recognized that electricity markets suffer from imperfections that hinder competition and are difficult to eliminate. The two most recognizable imperfections are the lack of significant price-elastic demand in the Real-Time Energy Market and barriers to entry for conventional and emerging resources. The standard framework for market-power mitigation is grounded in the economic theory of an industrial organization taking account of dynamic effects of new entry that could challenge the incumbents and discipline them to behave competitively.

The Real-Time Energy Market poses unique challenges in that market transactions with durations as short as five minutes within a vast transmission network require close scrutiny of suppliers' conduct and the immediate impact of their offers on market prices. Market-power mitigation rules keep market power in-check when transmission, generation or other constraints create conditions that might allow the exercise of market power.

A performance-based competitiveness assessment refers to a risk-adjusted evidence-driven evaluation consistent with the market-power mitigation framework in ways that complement efficient price formation. In principle, a performance-based market-power mitigation framework comprises three basic measures: structure, conduct and impact on performance.

Structure. A market is unable to sustain vigorous competition unless there are sufficient suppliers. The most commonly used structural measures include the Herfindahl-Hirschman Index (HHI),[18] the Pivotal Supplier Index (PSI),[19] the Residual Supply Index (RSI),[20] the Forward Hedging Ratio (FHR),[21] and the Lerner Index (LI).[22]

Conduct. When the market is structurally competitive, the premise is that because of vigorous competition, resource offers reflect true costs (including opportunity costs) and the market price would be approximately equal to the short-run marginal cost. However, when a market is structurally not competitive, a seller may gain supernormal profits through physical or economic withholding by raising its offer above the marginal cost. A conduct test determines whether the offers exceed a pre-determined reference level by an amount greater than a pre-specified threshold. Since the reference level may potentially set market prices, the choice of the threshold represents an important regulatory sub-delegation to ensure just and reasonable rate-making. In principle, the choice of threshold is preferably based on sound and "intelligible principle." Realistically, to accommodate the many uncertainties, some tolerance may be allowed to avoid over-mitigation.[23] In practice, the reference level could be based on an estimate of the resource's market cost (cost-based offer) or a historical average of the supplier's bids (default bid). For bids that fail the conduct screen, an impact analysis is performed to evaluate the impact of the offending bids on market outcomes.

Impact. Impact tests are applied only when the conduct thresholds are violated. These tests examine the impact of the supplier's offer for a resource by measuring the difference between the market price without and with mitigation of that offer. If this difference is sufficiently large, for example, exceeding a pre-specified threshold, then the supplier's offer can be mitigated. If a market seller is found to not be able to impact market prices, it will not be mitigated. Only those offers deemed to have an impact on the market-clearing price are subject to possible mitigation.

The standard remedy when the conduct and impact tests indicate insufficient competitive pressure — and the resource owner fails to provide an adequate explanation — is to mitigate the supplier's offer to the resource's reference level as adjusted using current data on fuel cost. The reference level is then the offer that is included in the merit order for dispatch optimization for determination of market prices. A key challenge with the addition of conduct and impact measures is the need to choose a reasonable threshold in a manner that ensures just and reasonable rates.

---

[18] See Footnote 2.

[19] The Pivotal Supplier Index (PSI) for structural deficiency identifies whether a supplier is pivotal, i.e. the resource requirements cannot be met without the units owned by that supplier. The test can be applied to identify whether a local area is import constrained and therefore has local market power when offers from outside that area cannot be used. A market seller is deemed to have market power when it is a pivotal supplier controlling resources needed to meet load requirements and thus has the ability to unilaterally raise the market clearing price by physical or economic withholding. FERC has accepted HHI and PSI as two standard structural measures of the horizontal market power for the energy market

[20] The Residual Supply Index (RSI) measures the percentage of load (MWh) that can be met without the largest supplier. It indicates the potential of individual bidders to influence the market clearing price. Like PSI, RSI reflects three key factors affecting market outcomes: (1) demand, (2) total available supply and (3) large suppliers' capacity share and contract position. Further, RSI measures the supply sufficiency relative to demand assuming the largest supplier withholds its entire capacity. Empirical data shows clear correlation between RSI and system price-cost mark-up.

[21] The ratio of forward contract over the total supply provides an important dynamic structural indicator of market performance. Forward contracting provides an important risk management tool that facilitates the competitive of wholesale and retail transactions. It hedges against short-term price volatility and promotes competitive retail offerings. It also incents generators to offer generation competitively.

[22] The conventional Lerner Index, defined as the price-cost margin in percentage terms, is widely used to assess the competitiveness of market outcomes in a way that reflects demand elasticity and market concentration.

[23] See Kelly, S (Hon.), M. F. Vouras and J. S. Amerkhail (2005) *The Subdelegation Doctrine and the Application of Reference Prices in Mitigating Market Power*, Energy Law Journal, Vol. 46, No. 2.

Under the current market-power mitigation rule, PJM's market has produced some puzzling results that are not always consistent with optimal behavior in competitive markets.[24] All market-power mitigation rules rely on the use of reference levels or default bids as substitutes for suppliers' offers, and these offers are deemed non-competitive. PJM's market-power mitigation rule adopts reference levels based on the cost-based offers that are formed according to fuel cost policy and opportunity cost calculation. The cost-based offers have the potential to set market prices when they replace suppliers' bids in correcting market distortions due to market-power abuse. Cost-based offers are a predetermined proxy for short-run marginal costs. Since cost-based offers are always calculated in advance, but the actual short-run marginal costs vary with dynamic circumstances, the use of cost-based offers is never foolproof.

The capacity market is fundamentally different from the energy market. Unlike energy, capacity is not a final consumable product and does not have a well-defined demand function. The capacity market provides a competitive mechanism to ensure revenue sufficiency subject to the resource adequacy requirement. The capacity market is basically a market for entry, and the market-power mitigation measure should focus on contestability, which is the ease with which suppliers can enter and leave the market.[25] The demand function (variable resource requirement or VRR curve) for capacity auctions is a derived demand function, while the VRR curve has built-in a revenue capping mechanism. The three-pivotal supplier (TPS) test may be duplicative of the effects of the VRR mechanism while raising the barrier to entry.

PJM believes that the capacity market power mitigation rule based on the TPS test may have become overly conservative. In 2018, all capacity market sellers failed the TPS test, and as a result, the 2018 SOM concluded that the capacity market was uncompetitive. Nonetheless, without applying a properly developed conduct and impact test, there was no clear evidence for non-competitive behavior or adverse impacts on market performance. PJM's analysis indicates that the impact of physical withholding by the single largest and potentially pivotal supplier on market performance (measured by the market surplus) was lower in 2018 than in 2017, but the revenue loss (thus the cost) of physical withholding for the potential single pivotal supplier was higher in 2018 than in 2017.

This result indicates that the incentive to exercise market power and the market impact of potential exercise of market power were both lower in 2018 than in 2017, contradicting the 2017/2018 SOM conclusions that the capacity market was competitive in 2017 but not in 2018. PJM believes that IMM's conclusion is based on an incomplete analysis that strongly depends upon the assumptions that underlie PJM's current market-power mitigation rule. In other words, the assumption that the unit-specific avoidable cost rate as calculated by the IMM is the only valid competitive offer that underlies the current market-power mitigation mechanism is too limited, and thus the IMM's analytical framework is flawed. On the other hand, PJM agrees with the IMM that that alternative measures of market-power mitigation need to be explored. To enhance competitive market performance, PJM is investigating conduct/impact-driven market-power mitigation rules that augment an appropriate structure-based rule.

[24] For example, price-based offers may be puzzlingly lower than cost-based offers. Price-cost markups may be negative an indication of the inaccuracy of the cost-based offer. Generators offer operating parameters inflexibly, though this may be cofounded with withholding.

[25] Generally, barrier to entry could be raised by economies of scale, fixed costs, inelastic demand and risk exposures. When the cost of entry is low, even if there are only a few incumbent suppliers, a market could still perform competitively. However, capacity market is not intended to address all potential barriers including obtaining CTRs, land use barriers, state siting barriers, state subsidies for existing units etc. etc.

Moving Forward

PJM is confident that the market results of 2018 support market price formation goals improving transparency, efficiency, incentive compatibility and revenue sufficiency for a resilient market design. PJM agrees with the IMM's conclusions regarding the competitiveness of the PJM market results except for the capacity market, where PJM believes that the IMM's conclusion lacks appropriate support based on a properly developed performance-based competitiveness assessment. PJM further believes that the capacity market can benefit from new aggregate market-power mitigation measures. In response to the GreenHat Energy default, PJM has initiated an expedited stakeholder effort to consider market rule changes to reduce market and default risks in PJM's markets.

PJM looks forward to working with the IMM and stakeholders to address the issues and recommendations contained in the 2018 State of the Market Report to advance future market evolution. Going forward, PJM anticipates continued opportunities to enhance the resilience of Energy, Reserve, capacity and FTR markets.

PJM Response to IMM Recommendations from the 2018 State of the Market Report

This section provides a more detailed PJM response to the recommendations contained within the 2018 State of the Market Report (2018 SOM)[26]. In 2018, the IMM introduced 36 new recommendations and marked two recommendations as Adopted. Many of the IMM recommendations are repeated from past State of the Market Reports. PJM has conducted an in-depth review of all 192 recommendations and has classified them into three categories: Actionable, Assessment and Archived.

1. **Actionable** – PJM considers these recommendations the highest priority, which upon adoption will have the greatest impact to the market performance. PJM plans to take action to address these recommendations in the coming year.
2. **Assessment** – PJM believes that these recommendations are of medium-to-high importance but need further investigation and analysis prior to determining if they are actionable.
3. **Archived** – The remaining recommendations are currently archived. PJM does not plan to take further actions on these recommendations at the current time. These recommendations may have been proposed by PJM but rejected by FERC or did not reach consensus among stakeholders. Some recommendations are out of PJM's purview and are directed to another party such as a state public utility commission. Other recommendations are archived because PJM disagrees with them or believes that they are low priority.

Table 1. Recommendations by Section and Category

Section	Actionable	Assessment	Archived	Section Percentage
Ancillary Services	8	10	4	11%
Capacity Market	0	9	16	13%
Demand Response	0	3	23	14%
Energy Market	3	9	26	20%
Energy Uplift	1	4	20	13%
Environmental	0	0	4	2%
FTRs & ARRs	4	6	9	10%
Interchange Transactions	0	0	13	7%
Planning	0	3	17	10%
Total Recommendations	**16**	**43**	**133**	**192**
Status Percentage	**8%**	**23%**	**69%**	

The PJM stakeholder process is an important decision-making mechanism that helps guide the resolution of issues identified by PJM, the FERC or PJM members, including issues brought forward by the IMM. The Markets & Reliability Committee (MRC), supported by the three lower-level committees, the Operating Committee (OC), the Market Implementation Committee (MIC) and the Planning Committee (PC), is responsible for undertaking issues that impact PJM Planning, Operations and Markets, and for designing proposals that resolve these issues.

Many of the recommendations that PJM has identified as Actionable or Assessment are discussed within the stakeholder process, where PJM staff presents education and analysis to define the issue and stakeholders participate in discussions to provide input and propose solutions. The summary sections below highlight stakeholder efforts that occurred in 2018,

[26] Monitoring Analytics, LLC. 2018 State of the Market Report for PJM. Volume 2: Detailed Analysis. March 14, 2019

and stakeholder efforts planned for 2019 that seek to address SOM recommendations. While efforts on the part of PJM and stakeholders may not fully address the recommendation to its exact intent, the summaries below provide a broader theme for why recommendations in each of the market areas have been categorized as Actionable or Assessment.

Energy Price Formation Proposal Recommendations

Several of the IMM's recommendations identified within the Ancillary Services section have been proposed in PJM's recent Section 206 Enhanced Price Formation in Reserve Markets filing, Docket No. ER19-1486-000.[27] The IMM has presented recommendations related to improving PJM's Reserve Markets, including modifications to the Tier 1 and Tier 2 Synchronized Reserve products and the Day-Ahead Scheduling Reserve (DASR) Market.

As part of PJM's proposal, the Tier 1 and Tier 2 Synchronized Reserve products would be consolidated into a single synchronized reserve product and the $7.50/MWh offer margin would be reduced to the expected value of the penalty, which is near zero. In addition, PJM's proposal strengthens the synchronized reserve must-offer requirement, and addresses the IMM recommendations:

- That the $7.50/MWh margin be eliminated from the definition of the cost of Tier 2 synchronized reserve because it is a markup and not a cost
- That the rule requiring that Tier 1 synchronized reserve resources are paid the Tier 2 price when the non-synchronized 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

Consolidating both synchronized reserve products into a unified product that is compensated at the applicable clearing price for the assigned reserve amount will improve the performance of the synchronized reserve resources and will eliminate the need for operator biasing in the determination of the synchronized reserve requirements. This change addresses the IMM recommendation:

- That PJM be more explicit and transparent about why Tier 1 biasing is used in defining demand in the Tier 2 Synchronized Reserve Market. The IMM recommends that PJM define rules for estimating Tier 1 megawatts, define rules for the use and amount of Tier 1 biasing and identify the rule-based reasons for each instance of biasing.

Another part of PJM's proposal is to eliminate the DASR Market. Instead, PJM proposes to introduce both a 10-minute Day-Ahead Synchronized Reserve product and a 10-minute Day-Ahead Primary Reserve Product to align with the existing 10-minute Real-Time Synchronized Reserve product and the 10-minute Real-Time Primary Reserve product. Moreover, PJM proposes to add both a 30-minute Day-Ahead and a Real-Time Secondary Reserve product, where offers into the markets will be based on opportunity cost only. These proposed Reserve Market changes will address the IMM recommendations:

- That PJM modify the DASR Market to ensure that all resources cleared incur a real-time performance obligation
- That offers in the DASR Market be based on opportunity cost only in order to eliminate market power

Finally, if additional reserves are committed, PJM has committed to posting a reason code. This directly addresses the IMM recommendation:

- That a reason code be attached to every hour in which PJM market operations add additional DASR megawatts

[27] https://www.pjm.com/directory/etariff/FercDockets/4037/20190329-er19-1486-000.pdf

Energy Market and Transparency Recommendations

Delivering transparent data and information is a value-added service that PJM provides to its members and other interested parties. In 2018, PJM completed a stakeholder effort in response to FERC Order 844 to increase transparency into system conditions and other operator actions that result in prices and other settlement results such as uplift charges. The Market Operations Price Transparency Group was responsible for creating the Drivers of Uplift pjm.com page and identifying modifications to the confidentiality provisions contained within the Operating Agreement. The enhanced transparency efforts achieved by this group supported the now archived IMM recommendation:

- That PJM continue to enhance its posting of market data to promote market efficiency

At the September 27, 2018, MRC meeting, stakeholders endorsed multiple manual revisions, including a new section to Manual 14D – Appendix A that defines a process for behind-the-meter generation reporting and communication requirements for transmission owners. The proposal was developed by the Distributed Energy Resources Subcommittee (DERS) and gives PJM and transmission owners better observability into behind-the-meter generation resources. This change largely addresses the IMM recommendation:

- That PJM identify and collect data on available behind-the-meter generation resources, including nodal location information and relevant operating parameters

In 2019, PJM will continue to assess opportunities to enhance market rules associated with reporting and transparency to further address the IMM recommendations:

- That PJM market rules require the fuel type be identified for every price and cost schedule and PJM market rules remove nonspecific fuel types such as other or co-fire other from the list of fuel types available for market participants to identify the fuel type associated with their price and cost schedules
- That PJM increase the interaction of outage and operational restrictions data submitted by market participants via eDART/eGADs and offer data submitted via Markets Gateway

FTR Market Recommendations

In response to the GreenHat Energy, LLC default in PJM's Financial Transmission Rights (FTR) market on June 21, 2018, and the Report of the Independent Committee of Consultants to the PJM Board,[28] PJM has initiated an expedited stakeholder effort to consider FTR market rule changes to prevent, deter or mitigate future defaults in PJM's FTR market. The MRC approved the Financial Risk Mitigation Senior Task Force (FRMSTF) charter on April 25, 2019. The senior task force objectives will cover topics related to market rule updates, credit and risk management rule updates, membership qualifications and process updates and stakeholder process changes. By the end of 2019, the FRMSTF is expected to propose rule changes to the MRC that address each objective, including governing document revisions to implement the recommended FTR enhancements.

PJM has identified four FTR recommendations for action and will seek stakeholder and independent expert input for enhancements to address the following IMM recommendations:

- That the Long-Term FTR product be eliminated
- That PJM continue to review the FTR liquidation process

[28] https://www.pjm.com/-/media/library/reports-notices/special-reports/2019/report-of-the-independent-consultants-on-the-greenhat-default.ashx?la=en

- That PJM examine the source and sink node combinations available in the FTR market
- That the forfeiture amount from the FTR forfeiture rule be based on the correct hourly cost of an FTR, rather than a simple daily price divided by 24

PJM will assess six of the FTR recommendations to better understand the impact and benefit they provide. The IMM recommends:

- That the ARR/FTR design be modified to ensure that the rights to all congestion revenues are assigned to load.
- That, if the Long-Term FTR product is not eliminated, the Long-Term FTR Market 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.
- That that full capability of the transmission system 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.
- That, under current FTR design, all congestion revenue in excess of FTR target allocations be distributed to ARR holders on a monthly basis.
- That PJM improve transmission outage modeling in the FTR auction models, including the use of probabilistic outage modeling.
- That PJM continue to evaluate the bilateral indemnification rules and any asymmetries they may create.

Capacity Market Recommendations

On April 9, 2018, PJM filed the Capacity Repricing/Alternative MOPR-Ex Proposal in Docket No. ER18-1314.[29] PJM's filing included two just and reasonable approaches to minimize the impacts of state public policies on the PJM capacity market. In comments filed on May 25, 2018, the IMM supported the MORP-Ex proposal citing, "MOPR-Ex constitutes a necessary and proportional response to the negative impacts on wholesale power markets created by state specific subsidies for individual generating resources that are either uneconomic or are providing less than target returns to investors in competitive markets. MOPR-Ex is properly filed and should be approved."

On June 29, 2018, FERC issued an order rejecting the proposed revisions and initiating proceeding to: (i) modify PJM's MOPR such that it would apply to new and existing resources receiving out-of-market payments, regardless of resource type, with few to no exemptions; and (ii) allow resources that receive out-of-market payments to remain online on a resource-specific basis to be removed from the capacity market for a defined period of time.

Pursuant to this Order, PJM filed its capacity market reform proposal[30] on October 2, 2018; this proposal is still pending before FERC. In 2019, PJM will be evaluating enhancements to the Reliability Pricing Model, and as part of these review efforts, has identified the following capacity market recommendations for assessment. The IMM recommends:

- The enforcement of a consistent definition of capacity resource. The IMM 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

[29] PJM Interconnection, LLC. Capacity Repricing or in the Alternative MOPR-Ex Proposal. ER-18-1314-000. April 9, 2018.

[30] PJM Interconnection, LLC. Capacity Reform Filing. ER 18-1314-001. October 2, 2018

- Use of the Sustainable Market Rule (SMR) in order to protect competition in the capacity market from nonmarket revenues.
- 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.
- That modification to existing resource not be treated as new resources for purposes of market power-related offer caps or MOPR offer floors.
- 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 make-whole payments.
- That PJM develop a forward-looking estimate for the expected number of Performance Assessment Intervals (H) to use in calculating the Non-Performance Charge Rate. The MMU recommends that PJM develop a forward-looking estimate for the Balancing Ratio (B) during Performance Assessment Intervals (PAIs) to use in calculating the default offer cap. Both H and B parameters should be included in the annual review of planning parameters for the Base Residual Auction, and should incorporate the actual observed margins, and other assumptions consistent with the annual IRM study.
- That when expected H and B are not the same as the assumed levels used to calculate the default market seller offer cap of Net CONE times B, the offer cap be recalculated for each BRA using the fundamental economic logic for a competitive offer of a CP resource.
- That capacity market sellers be required to request the use of minimum MW quantities greater than 0 MW (inflexible sell offer segments) and that the requests should only be permitted for defined physical reasons.
- That a unit which is not capable of supplying energy consistent with its day-ahead offer reflect an appropriate outage.

Regulation Market Recommendations

For the past two years, PJM has supported ongoing Regulation Market enhancement discussions with the IMM and stakeholders within the Regulation Market Issues Senior Task Force (RMISTF). In June 2017, PJM stakeholders approved a joint PJM and IMM RMISTF proposal with 75 percent support. The proposal included a transition plan to replace the benefit factor (BF) with a regulation rate of technical substitution (RRTS) and use the RRTS in settlements, in place of mileage ratio. The proposal also scored performance based on a precision-only calculation and raised the minimum allowable participation threshold from 40 percent to 50 percent. On October 17, 2017, in Docket ER18-87-000,[31] PJM submitted Tariff and Operating Agreement revisions to FERC to improve the performance of the Regulation Market and to better reflect the value of contributions of specific regulation resources. On March 30, 2018, FERC issued an order rejecting the proposed revisions. On April 30, 2019, PJM submitted for a rehearing request of the rejected order, which was granted on May 29, 2018, though FERC has not issued an order on rehearing. Had this proposal not been denied by the FERC, it would have addressed four reoccurring Ancillary Services IMM recommendations:

- 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.
- 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 schedule.

[31] PJM Interconnection, LLC. Proposed Tariff Revisions to Implement Regulation Market Enhancements. October 17, 2017.

- 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 regulation resources within the hour.
- Enhanced documentation of the implementation of the Regulation Market design.

PJM will continue to assess Regulation Market products as it awaits a rehearing date to be issued.

On-going Stakeholder Efforts that Impact State of the Market Recommendations

There are several other high-priority recommendations that PJM agrees with and plans to take action on or would like to further examine in the stakeholder process throughout 2019 prior to deciding if action is necessary.

Fuel Cost Policies

Stakeholder discussions in the MIC's fuel cost policy special sessions have been productive in identifying improvements to market sellers' fuel cost policies. PJM, the IMM and stakeholders agree that fuel cost policy requirements should only apply to units that offer non-zero cost-based offers. With stakeholder endorsement, the requirement to submit zero-cost fuel cost policies will likely be eliminated in 2019. This seeks to address the IMM recommendation:

- That PJM change the fuel cost policy requirement to apply only to units that will be offered with non-zero cost-based offers. The PJM market rules should require that the cost-based offers of units without an approved fuel cost policy be set to zero.

The fuel cost policy special sessions are also assessing the recommendation associated with fuel procurement practices, including fuel contracts, by which the fuel procurement process may be included within the policy, but is not required for policy approval. The IMM recommends:

- That the tariff be changed to allow units to have fuel cost policies that do not include fuel procurement practices, including fuel contracts. Fuel procurement practices, including fuel contracts, may be used for the basis for fuel cost policies but should not be required.

Black Start Fuel Assurance

PJM initiated a stakeholder effort in early 2019 to improve fuel assurance for new black start resources. This issue is being worked under the Operating Committee, and will assess the ancillary service recommendation associated with resources that share oil tanks, by determining the appropriate allocation of onsite fuel storage to minimum tank suction level (MTSL) requirements for black start service. Pending stakeholder support to allocate the proportional share of MTSL to black start fuel storage costs, PJM will clarify how the MTSL is calculated for black start resources that share oil tanks in the PJM Tariff. These stakeholder efforts address the IMM recommendation:

- That for oil tanks shared with other resources that only a proportionate share of the minimum tank suction level (MTSL) be allocated to black start service. The IMM further recommends that the PJM tariff be updated to clearly state how MTSL will be calculated for black start units sharing oil tanks.

Primary Frequency Response

The Primary Frequency Response Senior Task Force (PFRSTF) was initiated in mid-2017 to evaluate and strengthen generators' primary frequency response requirement. The issue was discussed with stakeholders for more than a year, and on December 3, 2018, the PFRSTF voted on three proposed solution packages to define a primary frequency response requirement for new and existing resources and compensation associated with performance. No package received majority support, and a non-binding poll to maintain status quo garnered 73 percent support.

The PFRSTF Chair reviewed this outcome with the MRC on December 20, 2018, and requested the PFRSTF go on hiatus for one year. Throughout 2019, PJM will continue to monitor primary frequency response performance and provide quarterly updates to the OC. The PFRSTF Chair will return to the MRC in January 2020 to provide an update and seek guidance for how to proceed with future PFRSTF efforts based on 2019 observations. PJM has identified two of the ancillary service recommendations associated with Primary Frequency Response for assessment in 2019. These efforts address the IMM recommendations:

- 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 and that compensation is provided through the capacity and energy markets.
- That capability to operate under the proposed deadband (+/- 0.036 HZ) and droop (5 percent) settings in order to provide frequency control be mandated as a condition of interconnection and that such capability be required of both new and existing resources. The MMU recommends that no additional compensation be provided as the current PJM market design provides adequate compensation

Planning Process Enhancements

PJM is engaged with stakeholders in the PC to assess the current process and manuals for the integration of supplemental projects into the RTEP. PJM received an Order from the FERC, Docket Nos. EL-16-71-000 and ER17-179-000,[32] requiring revisions to Attachment M-3 to clarify that:

> *"the PJM Transmission Owners will convene a minimum of three separate meetings as part of the transmission planning process for Supplemental Projects: (1) a meeting to discuss the inputs to the transmission planning process, including models, criteria and assumptions; (2) a meeting to discuss the needs identified as a result of that process; and (3) a meeting to discuss potential solutions to meet those needs. …the purpose of these separate meetings is to ensure that PJM stakeholders have adequate opportunity to review the subject matter to be discussed at each meeting – particularly the need(s) driving a Supplemental Project – and to do so at a point in the transmission planning process at which their participation may still be useful (i.e., before the PJM Transmission Owners have taken steps to develop the Supplemental Projects that would render moot the feedback that stakeholders might provide)."*

PJM is responsible for facilitating the Transmission Owner Attachment M-3 process and is working with stakeholders to assess ways in which the process can be enhanced for greater transparency, including quarterly lessons-learned meetings while still respecting authority under the PJM Tariff. These PC efforts address the IMM recommendation:

- 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.

The MIC is responsible for changes proposed to the capacity auction process, terminating Capacity Interconnection Rights (CIRs) for unqualified capacity resources. The MIC recently reviewed the process for granting must-offer exceptions and developed proposals that clarify acceptable reasons for receiving a Capacity Performance must-offer exception, which addresses the IMM recommendation:

[32] FERC Ruling on Docket EL-16-71-000 and ER17-179-000. February 23, 2018.

- That rules be implemented to ensure that CIRs are terminated within one year if units cannot qualify to be capacity resources and, if requested, after on CP must offer exception to permit the issue of CP status to be addressed.

In early 2019, the IMM presented a new draft problem statement and issue charge to initiate a stakeholder effort via the PC to review the benefit/cost analysis used in the market efficiency planning process, and to propose improvements that are identified. This PC stakeholder effort will address the IMM recommendation:

- That PJM modify the rules governing benefit/cost analysis, the evaluation process for selecting amount competing efficiency projects and cost allocation for economic projects in order to ensure that all costs, including congestion costs, in all zones are included.

Appendix – Complete List of Recommendations[33]

	ACTIONABLE				
Section	2018 Recommendation	Priority	Year Reported	Status	PJM Status 2019
Energy Market	The MMU recommends that PJM change the Fuel Cost Policy requirement to apply only to units that will be offered with non-zero cost-based offers. The PJM market rules should require that the cost-based offers of units without an approved Fuel Cost Policy be set to zero.	Low	2018	Not Adopted	Actionable
Energy Market	The MMU recommends that PJM identify and collect data on available behind the meter generation resources, including nodal location information and relevant operating parameters.	Low	2013	Partially Adopted	Actionable
Energy Market	The MMU recommends that PJM market rules require the fuel type be identified for every price and cost schedule and PJM market rules remove nonspecific fuel types such as other or co-fire other from the list of fuel types available for market participants to identify the fuel type associated with their price and cost schedules.	Medium	2015	Partially Adopted	Actionable
Energy Uplift	The MMU recommends that if PJM believes it appropriate to implement CT price setting logic, PJM first initiate a stakeholder process to determine whether such modification is appropriate. PJM should file any proposed changes with FERC to ensure review. Any such changes should be incorporated in the PJM tariff.	Medium	2016	Not Adopted	Actionable
Ancillary Services	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.	High	2010	Not Adopted *FERC Rejected, pending rehearing*	Actionable
Ancillary Services	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.	Medium	2018	Not Adopted	Actionable
Ancillary Services	The MMU recommends that the rule requiring that tier 1 synchronized reserve resources are 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.	High	2013	Not Adopted	Actionable
Ancillary Services	The MMU recommends that PJM be more explicit and transparent about why tier 1 biasing is used in defining demand in the Tier 2 Synchronized Reserve Market. The MMU recommends that PJM define rules for estimating tier 1 MW, define rules for the use and amount of tier 1 biasing and identify the rule based reasons for each instance of biasing.	Medium	2012	Not Adopted	Actionable
Ancillary Services	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.	Medium	2018	Not Adopted	Actionable
Ancillary Services	The MMU recommends that a reason code be attached to every hour in which PJM market operations add additional DASR MW.	Medium	2015	Not Adopted	Actionable
Ancillary Services	The MMU recommends that PJM modify the DASR Market to ensure that all resources cleared incur a real-time performance obligation.	Low	2013	Not Adopted	Actionable
Ancillary Services	The MMU recommends that offers in the DASR Market be based on opportunity cost only in order to eliminate market power.	Low	2018	Not Adopted	Actionable
FTRs & ARRs	The MMU recommends that the Long-Term FTR product be eliminated.	High	2018	Not Adopted	Actionable
FTRs & ARRs	The MMU recommends that PJM continue to review the FTR liquidation process.	High	2018	Not Adopted	Actionable
FTRs & ARRs	The MMU recommends that PJM reexamine the source and sink node combinations available in the FTR market.	High	2018	Not Adopted	Actionable
FTRs & ARRs	The MMU recommends that the forfeiture amount from the FTR forfeiture rule be based on the correct hourly cost of an FTR, rather than a simple daily price divided by 24.	High	2018	Not Adopted	Actionable

[33] Monitoring Analytics, LLC. 2018 State of the Market Report for PJM. Volume 2: Detailed Analysis. March 14, 2019

ASSESSMENT					
Section	2018 Recommendation	Priority	Year Reported	Status	PJM Status 2019
Energy Market	The MMU recommends that the tariff be changed to allow units to have Fuel Cost Policies that do not include fuel procurement practices, including fuel contracts. Fuel procurement practices, including fuel contracts, may be used for the basis for Fuel Cost Policies but should not be required.	Low	2018	Not Adopted	Assessment
Energy Market	The MMU recommends revising the pumped hydro fuel cost calculation to include day-ahead and real-time power purchases.	Low	2016	Not Adopted	Assessment
Energy Market	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.	Medium	2015	Not Adopted	Assessment
Energy Market	The MMU recommends, in order to ensure effective market power mitigation when the TPS test is failed, that markup be constant across the full MWh range of price and cost-based offers.	High	2015	Not Adopted	Assessment
Energy Market	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.	Medium	2012	Partially Adopted	Assessment
Energy Market	The MMU recommends that the parameters which determine nonperformance charges and the amounts of uplift payments should reflect the flexibility goals of the capacity performance construct. The operational parameters used by generation owners to indicate to PJM dispatchers what a unit is capable of during the operating day should not determine capacity performance assessment or uplift payments.	Medium	2015	Partially Adopted	Assessment
Energy Market	The MMU recommends that PJM institute rules to assess a penalty for resources that choose to submit real-time values that are less flexible than their unit specific parameter limits or approved parameter limit exceptions based on tariff defined reasons.	Medium	2018	Not Adopted	Assessment
Energy Market	The MMU recommends that PJM increase the interaction of outage and operational restrictions data submitted by Market Participants via eDART/eGADs and offer data submitted via Markets Gateway.	Low	2017	Not Adopted	Assessment
Energy Uplift	The MMU recommends that PJM initiate an analysis of the reasons why a significant number of combustion turbines and diesels scheduled in the Day-Ahead Energy Market are not called in real time when they are economic.	Medium	2012	Not Adopted	Assessment
Energy Uplift	The MMU recommends modifications to the calculation of lost opportunity costs credits paid to wind units. The lost opportunity cost 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.	Low	2012	Not Adopted	Assessment
Energy Uplift	The MMU recommends that PJM develop and implement an accurate metric to define when a unit is following dispatch to determine eligibility to receive balancing operating reserve credits and for assessing generator deviations.	Medium	2018	Not Adopted	Assessment
Energy Uplift	The MMU recommends that PJM eliminate the exemption for fast start resources (CTs and diesels) from the requirement to follow dispatch. The performance of these resources should be evaluated in a manner consistent with all other resources.	Medium	2018	Not Adopted	Assessment
Capacity Market	The MMU recommends the enforcement of a consistent definition of capacity resource. 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.	High	2013	Not Adopted	Assessment
Capacity Market	The MMU recommends use of the Sustainable Market Rule (SMR) in order to protect competition in the capacity market from nonmarket revenues.	High	2016	Not Adopted	Assessment
Capacity Market	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.	High	2013	Not Adopted	Assessment
Capacity Market	The MMU recommends that modification to existing resource not be treated as new resources for purposes of market power related offer caps or MOPR offer floors.	Low	2012	Not Adopted	Assessment
Capacity	The MMU recommends that the RPM market power mitigation rule be modified to	Medium	2017	Not	Assessment

ASSESSMENT					
Section	2018 Recommendation	Priority	Year Reported	Status	PJM Status 2019
Market	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 make whole payments.			Adopted	
Capacity Market	The MMU recommends that PJM develop a forward looking estimate for the expected number of Performance Assessment Intervals (H) to use in calculating the Non-Performance Charge Rate. The MMU recommends that PJM develop a forward looking estimate for the Balancing Ratio (B) during Performance Assessment Intervals (PAIs) to use in calculating the default offer cap. Both H and B parameters should be included in the annual review of planning parameters for the Base Residual Auction, and should incorporate the actual observed margins, and other assumptions consistent with the annual IRM study.	High	2017	Not Adopted	Assessment
Capacity Market	The MMU recommends that when expected H and B are not the same as the assumed levels used to calculate the default market seller offer cap of Net CONE times B, the offer cap be recalculated for each BRA using the fundamental economic logic for a competitive offer of a CP resource.	High	2017	Not Adopted	Assessment
Capacity Market	The MMU recommends that capacity market sellers be required to request the use of minimum MW quantities greater than 0 MW (inflexible sell offer segments) and that the requests should only be permitted for defined physical reasons.	Medium	2018	Not Adopted	Assessment
Capacity Market	The MMU recommends that a unit which is not capable of supplying energy consistent with its day-ahead offer reflect an appropriate outage.	Medium	2009	Not Adopted	Assessment
Demand Response	The MMU recommends that PRD be required to respond during a PAH to be consistent with all CP resources.	High	2017	Not Adopted	Assessment
Demand Response	The MMU recommends that 30 minute pre-emergency and emergency demand response be considered to be 30 minute reserves.	Medium	2018	Not Adopted	Assessment
Demand Response	The MMU recommends that energy efficiency MW not be included in the PJM capacity market and that PJM should ensure that the impact of EE measures on the load forecast is incorporated immediately rather than the existing lag.	Medium	2018	Not Adopted	Assessment
Ancillary Services	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.	High	2012	Not Adopted *FERC Rejected, pending rehearing*	Assessment
Ancillary Services	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 schedule.	Medium	2010	Not Adopted *FERC Rejected, pending rehearing*	Assessment
Ancillary Services	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 regulation resources within the hour.	Medium	2016	Not Adopted *FERC Rejected, pending rehearing*	Assessment
Ancillary Services	The MMU recommends enhanced documentation of the implementation of the Regulation Market design.	Medium	2010	Not Adopted *FERC Rejected, pending rehearing*	Assessment
Ancillary Services	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.	Medium	2013	Partially Adopted	Assessment
Ancillary Services	The MMU recommends that, for calculating the penalty for a tier 2 resource failing to meet its scheduled obligation during a spinning event, the definition of the IPI be changed from the average number of days between events to the actual number of days since the last event greater than 10 minutes.	Medium	2018	Not Adopted	Assessment
Ancillary Services	The MMU recommends that aggregation not be permitted to offset unit specific penalties for failure to respond to a synchronized reserve event.	Medium	2018	Not Adopted	Assessment

	ASSESSMENT				
Section	2018 Recommendation	Priority	Year Reported	Status	PJM Status 2019
Ancillary Services	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 and that compensation is provided through the capacity and energy markets.	Medium	2018	Not Adopted	Assessment
Ancillary Services	The MMU recommends that for oil tanks shared with other resources that only a proportionate share of the minimum tank suction level (MTSL) be allocated to black start service. The MMU further recommends that the PJM tariff be updated to clearly state how MTSL will be calculated for black start units sharing oil tanks.	Medium	2017	Not Adopted	Assessment
Ancillary Services	The MMU recommends that capability to operate under the proposed deadband (+/- 0.036 HZ) and droop (5 percent) settings in order to provide frequency control be mandated as a condition of interconnection and that such capability be required of both new and existing resources. The MMU recommends that no additional compensation be provided as the current PJM market design provides adequate compensation	Low	2017	Not Adopted	Assessment
Planning	The MMU recommends that rules be implemented to ensure that CIRs are terminated within one year if units cannot qualify to be capacity resources and, if requested, after one CP must offer exception to permit the issue of CP status to be addressed.	Low	2018	Not Adopted	Assessment
Planning	The MMU recommends that PJM modify the rules governing benefit/cost 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 congestion costs, in all zones are included.	Medium	2018	Not Adopted	Assessment
Planning	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.	Medium	2017	Not Adopted	Assessment
FTRs & ARRs	The MMU recommends that the ARR/FTR design be modified to ensure that the rights to all congestion revenues are assigned to load.	High	2015	Not Adopted	Assessment
FTRs & ARRs	The MMU recommends that, if the Long Term FTR product is not eliminated, Long Term FTR Market 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.	High	2017	Not Adopted	Assessment
FTRs & ARRs	The MMU recommends that that full capability of the transmission system 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.	High	2017	Not Adopted	Assessment
FTRs & ARRs	The MMU recommends that, under current FTR design, all congestion revenue in excess of FTR target allocations be distributed to ARR holders on a monthly basis.	High	2018	Not Adopted	Assessment
FTRs & ARRs	The MMU recommends that PJM improve transmission outage modeling in the FTR auction models, including the use of probabilistic outage modeling.	Low	2013	Not Adopted	Assessment
FTRs & ARRs	The MMU recommends that PJM continue to evaluate the bilateral indemnification rules and any asymmetries they may create.	Low	2018	Not Adopted	Assessment

	ARCHIVED				
Section	2018 Recommendation	Priority	Year Reported	Status	PJM Status 2019
Energy Market	The MMU recommends that the market rules should explicitly require that offers in the Day-Ahead 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 and where 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.	Medium	2009	Not Adopted	Archived
Energy Market	The MMU recommends that PJM require that all fuel cost policies be algorithmic, verifiable, and systematic, and accurately reflect short run marginal costs.	Medium	2016	Not Adopted	Archived
Energy Market	The MMU recommends that Manual 15 (Cost Development Guidelines) be replaced with a straightforward description of the components of cost-based offers based on short run marginal costs and the correct calculation of cost-based offers.	Medium	2016	Not Adopted	Archived
Energy Market	The MMU recommends removal of all use of FERC System of Accounts in the Cost Development Guidelines.	Medium	2016	Not Adopted	Archived
Energy Market	The MMU recommends the removal of all use of cyclic starting and peaking factors from the Cost Development Guidelines	Medium	2016	Not Adopted	Archived
Energy Market	The MMU recommends the removal of all labor costs from the Cost Development Guidelines	Medium	2016	Not Adopted	Archived
Energy Market	The MMU recommends changing the definition of the start heat input for combined cycles to include only the amount of fuel used from firing each combustion turbine in the combined cycle to the breaker close of each combustion turbine.	Medium	2016	Not Adopted	Archived
Energy Market	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.	Medium	2016	Not Adopted	Archived
Energy Market	The MMU recommends revisions to the calculation of energy market opportunity costs to incorporate all time based offer parameters and all limitations that impact the opportunity cost of generating unit output.	Medium	2016	Partially Adopted	Archived
Energy Market	The MMU recommends removing the catastrophic designation for force majeure fuel supply limitations in Schedule 2.	Medium	2016	Not Adopted	Archived
Energy Market	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.	High	2016	Partially Adopted	Archived
Energy Market	The MMU recommends that in order to ensure effective market power mitigation when the TPS test is failed, the operating parameters in the cost-based offer and the price-based parameter limited schedule (PLS) offer be at least as flexible as the operating parameters in the available price-based non-PLS offer, and that the price-MW pairs in the price-based PLS offer be exactly equal to the price-based non-PLS offer.	High	2015	Not Adopted	Archived
Energy Market	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.	High	1999	Partially Adopted	Archived
Energy Market	The MMU recommends that Market Sellers not be allowed to designate any portion of an available Capacity Resource's ICAP equivalent of cleared UCAP capacity commitment as a Maximum Emergency offer at any time during the delivery year.	Medium	2012	Not Adopted	Archived
Energy Market	The MMU recommends that capacity performance resources and base capacity resources (during the June through September period) 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.	Medium	2015	Not Adopted	Archived
Energy Market	The MMU recommends that PJM not allow nuclear generators which do not respond to prices or which only respond to manual instructions from the dispatcher to set the LMPs in the real-time market.	Low	2016	Not Adopted	Archived
Energy Market	The MMU recommends that PJM document how LMPs are calculated when demand response is marginal.	Low	2014	Not Adopted	Archived
Energy Market	The MMU recommends that PJM not include the balancing ratios calculated for localized Performance Assessment Intervals (PAIs) in the capacity market default offer cap, and only include those events that trigger emergencies for at least a defined sub-zonal or zonal level.	Medium	2018	Not Adopted	Archived
Energy Market	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	Low	2018	Not Adopted	Archived

ARCHIVED					
Section	2018 Recommendation	Priority	Year Reported	Status	PJM Status 2019
	their resources				
Energy Market	The MMU recommends that PJM update the tariff to clarify that all generation resources are subject to unit specific parameter limits on their cost-based offers using the same standard and process as capacity performance capacity resources.	Medium	2018	Not Adopted	Archived
Energy Market	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; the use of constraint relaxation logic; and when the transmission penalty factors will be used to set the shadow price.	Medium	2015	Not Adopted *Stakehol-der Process*	Archived
Energy Market	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.	Low	2013	Partially Adopted	Archived
Energy Market	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.	Low	2013	Not Adopted	Archived
Energy Market	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.	Low	2013	Not Adopted	Archived
Energy Market	The MMU recommends that all buses with a net withdrawal be treated as load for purposes of calculating load and load-weighted LMP. 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.	Low	2013	Not Adopted	Archived
Energy Market	The MMU recommends that PJM continue to enhance its posting of market data to promote market efficiency.	Medium	2005	Partially Adopted	Archived
Energy Market	The MMU recommends that PJM clearly define the criteria for operator approval of RT SCED cases used to send dispatch signals to resources, and for pricing, to minimize operator discretion and implement a rule based approach.	High	2018	Not Adopted	Archived
Energy Uplift	The MMU recommends that uplift be paid only based on operating parameters that reflect the flexibility of the benchmark new entrant unit (CONE unit) in the PJM Capacity Market.	High	2018	Not Adopted	Archived
Energy Uplift	The MMU recommends that PJM not use closed loop interface 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.	Medium	2013	Not Adopted	Archived
Energy Uplift	The MMU recommends that PJM not use CT price setting logic to modify transmission line limits to artificially override the nodal prices that are based on fundamental LMP logic in order to reduce uplift.	Medium	2015	Not Adopted	Archived
Energy Uplift	The MMU recommends eliminating intraday time segments from the calculation of uplift payments and returning to calculating the need for uplift based on the entire 24 hour operating day.	High	2018	Not Adopted	Archived
Energy Uplift	The MMU recommends the elimination of the day-ahead operating reserves to ensure that units receive an energy uplift payment based on their real-time output and not their day-ahead scheduled output.	Medium	2013	Not Adopted	Archived
Energy Uplift	The MMU recommends enhancing the current energy uplift allocation rules to reflect the elimination of day-ahead operating reserves, the timing of commitment decisions and the commitment reasons.	High	2012	Not Adopted	Archived
Energy Uplift	The MMU recommends reincorporating the use of net regulation revenues as an offset in the calculation of balancing operating reserve credits.	Medium	2018	Not Adopted *Stakeho-lder Process*	Archived
Energy Uplift	The MMU recommends that self-scheduled units not be paid energy uplift for their startup cost when the units are scheduled by PJM to start before the self-scheduled hours.	Low	2013	Not Adopted *Stakeho-*	Archived

ARCHIVED

Section	2018 Recommendation	Priority	Year Reported	Status	PJM Status 2019
				lder Process	
Energy Uplift	The MMU recommends calculating LOC based on 24 hour periods for combustion turbines and diesels scheduled in the Day-Ahead Energy Market, but not committed in real time.	Medium	2014	Not Adopted	Archived
Energy Uplift	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.	Medium	2015	Not Adopted	Archived
Energy Uplift	The MMU recommends that only flexible fast start units (startup plus notification times of 10 minutes or less) and short minimum run times (one hour or less) be eligible by default for the LOC compensation to the 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	Medium	2015	Not Adopted	Archived
Energy Uplift	The MMU recommends that up to congestion transactions be required to pay energy uplift charges for both the injection and the withdrawal sides of the UTC.	High	2011	Not Adopted	Archived
Energy Uplift	*The MMU recommends eliminating the use of internal bilateral transactions (IBTs) in the calculation of deviations used to allocate balancing operating reserve charges.*	*High*	*2013*	*Adopted 2018*	*Archived*
Energy Uplift	The MMU recommends allocating the energy uplift payments to units scheduled 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.	Medium	2014	Not Adopted *Stakeho-lder Process*	Archived
Energy Uplift	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 operating reserve credits calculation.	High	2012	Not Adopted *Stakeho-lder Process*	Archived
Energy Uplift	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, which is currently allocated solely to real-time RTO load.	High	2013	Not Adopted	Archived
Energy Uplift	The MMU recommends that PJM revise Manual 11 attachment C consistent with the tariff to limit uplift compensation to offered costs. The Manual 11 attachment C procedure should describe the steps market participants must take to change the availability of cost-based energy offers that have been submitted day ahead. The MMU recommends that PJM eliminate Manual 11 attachment C procedure with the implementation of hourly offers (ER16-372-000).	Medium	2016	Not Adopted	Archived
Energy Uplift	The MMU recommends that PJM clearly identify and classify all reasons for incurring operating reserves in the Day-Ahead and the Real-Time Energy markets and the associated operating reserve 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 operating reserves.	Medium	2011	Partially Adopted	Archived
Energy Uplift	The MMU recommends that PJM revise the current operating reserve confidentiality rules in order to allow the disclosure of complete information about the level of operating reserve charges by unit and the detailed reasons for the level of operating reserve credits by unit in the PJM region.	High	2013	Partially Adopted	Archived
Energy Uplift	The MMU recommends that PJM pay uplift based on the offer at the lower of the actual unit output or the dispatch signal MW.	Medium	2018	Not Adopted	Archived
Capacity Market	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.	High	2016	Not Adopted	Archived
Capacity Market	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.	Medium	2013	Not Adopted	Archived
Capacity Market	The MMU recommends that the net revenue calculation 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 result of reflecting the actual flexibility is higher net revenues, which affect the parameters of the RPM demand curve and market outcomes.	High	2013	Not Adopted	Archived
Capacity Market	The MMU recommends that energy efficiency resources (EE) not be included on the supply side of the capacity market, because PJM's load forecasts now account for	Medium	2016	Not Adopted	Archived

A R C H I V E D

Section	2018 Recommendation	Priority	Year Reported	Status	PJM Status 2019
	future EE, unlike the situation when EE was first added to the capacity market. However, the MMU recommends that the PJM load forecast method should be modified so that EE impacts immediately affect the forecast without the long lag times incorporated in the current forecast method. If EE is not included on the supply side, the implementation of the EE add back mechanism should be modified to ensure that market clearing prices are not affected.				
Capacity Market	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.	Medium	2013	Not Adopted	Archived
Capacity Market	The MMU recommends that PJM offer to sell back capacity in incremental auctions only at the BRA clearing price for the relevant delivery year.	Medium	2017	Not Adopted	Archived
Capacity Market	The MMU recommends changing the RPM solution method to explicitly incorporate the cost of make whole payments in the objective function.	Medium	2014	Not Adopted	Archived
Capacity Market	The MMU recommends that PJM clear the capacity market based on nodal capacity resources locations and the characteristics of the transmission system consistent with the actual electrical facts of the grid. The current nested LDA structure used in the capacity market does not adequately represent all the capacity transfers that are feasible among LDAs. Absent a fully nodal capacity market clearing process, the MMU recommends that PJM use a nonnested model for all LDAs and specify a VRR curve for each LDA separately. 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 price separate if that is the result of the LDA supply curves and the transmission constraints.	Medium	2017	Not Adopted	Archived
Capacity Market	The MMU recommends that retroactive replacement transactions associated with a failure to perform during a PAH not be allowed and that, more generally, retroactive replacement capacity transactions not be permitted.	Medium	2016	Not Adopted	Archived
Capacity Market	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.	Low	2013	Not Adopted	Archived
Capacity Market	The MMU recommends that all capacity imports be required to be deliverable to PJM load 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.	High	2016	Not Adopted	Archived
Capacity Market	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 the unit offers in the capacity market.	High	2016	Not Adopted	Archived
Capacity Market	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. PJM has modified these rules, but the rules need additional clarification and operational details.	Low	2010	Partially Adopted	Archived
Capacity Market	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.	Low	2012	Partially Adopted	Archived
Capacity Market	The MMU recommends that RMR units recover all and only the incremental costs, including incremental investment costs, required by the 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.	Low	2010	Not Adopted	Archived
Capacity Market	The MMU recommends elimination of the cost of service recovery rate in OATT Section 119, and that RMR service should be provided under the deactivation avoidable cost rate in Part V. The MMU also recommends specific improvements to the DACR provisions.	Medium	2017	Not Adopted	Archived
Demand Response	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	High	2014	Not Adopted	Archived

ARCHIVED					
Section	2018 Recommendation	Priority	Year Reported	Status	PJM Status 2019
	be metered load, and that PJM forecasts immediately incorporate the impacts of demand side behavior.				
Demand Response	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.	Medium	2010	Not Adopted	Archived
Demand Response	The MMU recommends that the maximum offer for demand resources be the same as the maximum offer for generation resources.	Medium	2013	Not Adopted	Archived
Demand Response	The MMU recommends that the demand resources be treated as economic resource, 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.	High	2012	Not Adopted	Archived
Demand Response	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.	Low	2010	Not Adopted	Archived
Demand Response	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.	High	2013	Not Adopted	Archived
Demand Response	The MMU recommends that demand resources be required to provide their nodal location, comparable to generation resources.	High	2011	Not Adopted	Archived
Demand Response	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.	High	2015	Not Adopted	Archived
Demand Response	The MMU recommends that PJM not remove any defined subzones and maintain a public record of all created and removed subzones.	Low	2016	Not Adopted	Archived
Demand Response	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.	High	2015	Not Adopted	Archived
Demand Response	The MMU recommends that measurement and verification methods for demand resources be modified to reflect compliance more accurately.	Medium	2009	Not Adopted	Archived
Demand Response	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.	Medium	2012	Not Adopted	Archived
Demand Response	The MMU recommends that PJM adopt the ISO-NE five-minute metering requirements in order to ensure that dispatchers have the necessary information for reliability and that market payment to demand resources be calculated based on interval meter data at the site of the demand reductions.	Medium	2013	Not Adopted	Archived
Demand Response	The MMU recommends limited, extended summer and annual demand response event compliance be calculated on an hourly basis for noncapacity performance resources and on a five minute basis for all capacity performance resources and that the penalty structure reflect five minute compliance.	Medium	2013	Partially Adopted	Archived
Demand Response	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.	Low	2012	Not Adopted	Archived
Demand Response	The MMU recommends that shutdown cost be defined as the cost to curtail for a given period that does not vary with the measured reduction, for behind the meter generators, be the start cost defined in Manual 15 for generators.	Low	2012	Not Adopted	Archived
Demand Response	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.	Low	2015	Not Adopted	Archived
Demand Response	The MMU recommends that the tariff rules for demand response clarify that a resource and its CSP, if any, must notify PJM of materials 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.	Medium	2015	Not Adopted	Archived
Demand Response	The MMU recommends that there only be one demand response product in the capacity market, with an obligation to respond when called for any hours of the delivery year.	High	2011	Partially Adopted	Archived

ARCHIVED					
Section	2018 Recommendation	Priority	Year Reported	Status	PJM Status 2019
Demand Response	The MMU recommends that the lead times for demand resources be shortened to 30 minutes with an hour minimum dispatch for all resources.	Medium	2013	Partially Adopted	Archived
Demand Response	The MMU recommends setting the baseline for measuring capacity compliance under winter compliance at the customers' PLC, similar to GLD, to avoid double counting.	High	2010	Partially Adopted	Archived
Demand Response	The MMU recommends the Relative Root Mean Squared Test be required for all demand resources with a CBL.	Low	2017	Partially Adopted	Archived
Demand Response	The MMU recommends that the limits imposed on the pre-emergency and emergency demand response share of the Synchronized Reserve Market be eliminated.	Medium	2018	Not Adopted	Archived
Environmental	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.	Medium	2010	Not Adopted	Archived
Environmental	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.	High	2018	Not Adopted	Archived
Environmental	The MMU recommends that states consider the development of a multistate framework for RECs markets, for potential agreement on carbon pricing including the distribution of carbon revenues, and for coordination with PJM wholesale markets.	Medium	2018	Not Adopted	Archived
Environmental	The MMU recommends that jurisdictions with a renewable portfolio standard make the price and quantity data on supply and demand more transparent.	Low	2018	Not Adopted	Archived
Interchange Transactions	The MMU recommends that PJM implement rules to prevent sham scheduling. The MMU recommends that PJM apply after the fact market settlement adjustments to identified sham scheduling segments to ensure that market participants cannot benefit from sham scheduling.	High	2012	Not Adopted *Stakeho-lder Process*	Archived
Interchange Transactions	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.	Medium	2013	Not Adopted	Archived
Interchange Transactions	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.	Medium	2013	Not Adopted	Archived
Interchange Transactions	The MMU recommends that PJM end the practice of maintaining outdated definitions of interface pricing points, eliminate the NIPSCO, Southeast and Southwest interface pricing points from Day-Ahead and Real-Time Energy Markets and, with VACAR, assign the transactions created under the reserve sharing agreement to the SouthIMP/EXP pricing point.	Medium	2013	Not Adopted	Archived
Interchange Transactions	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.	Medium	2013	Not Adopted	Archived
Interchange Transactions	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.	Low	2009	Not Adopted	Archived
Interchange Transactions	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.	Medium	2003	Not Adopted	Archived
Interchange Transactions	The MMU recommends that PJM explore an interchange optimization solution with its neighboring balancing authorities that would remove the need for market participants to schedule physical transactions across seams. Such a solution would include an optimized, but limited, joint dispatch approach that uses supply curves and treats seams between balancing authorities as constraints, similar to other constraints within an LMP market.	Medium	2014	Not Adopted	Archived
Interchange Transactions	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.	Medium	2012	Not Adopted	Archived

	ARCHIVED				
Section	2018 Recommendation	Priority	Year Reported	Status	PJM Status 2019
Interchange Transactions	The MMU recommends that PJM immediately provide the required 12-month notice to Duke Energy Progress (DEP) to unilaterally terminate the Joint Operating Agreement.	Low	2013	Not Adopted	Archived
Interchange Transactions	The MMU recommends that PJM Settlement Inc. immediately request a credit evaluation from all companies that engaged in up to congestion transactions between September 8, 2014 and December 31, 2015. If PJM has the authority, PJM should ensure that the potential exposure to uplift for that period be included as a contingency in the companies' calculations for credit levels and/or collateral requirements. If PJM does not have the authority to take such steps, PJM should request guidance from FERC.	Low	2015	Not Adopted	Archived
Interchange Transactions	The MMU recommends that the emergency interchange cap be replaced with a market based solution.	Low	2015	Not Adopted	Archived
Interchange Transactions	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.	Medium	2015	Partially Adopted	Archived
Ancillary Services	The MMU recommends that all data necessary to perform the Regulation Market three pivotal supplier test be saved so that the test can be replicated.	Medium	2016	Adopted 2018	Archived
Ancillary Services	The MMU recommends that PJM be required to save data elements necessary for verifying performance of the Regulation Market	Medium	2010	Not Adopted	Archived
Ancillary Services	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.	Medium	2016	Not Adopted	Archived
Ancillary Services	The MMU recommends that payments for reactive capability, if continued, be based on the 0.90 power factor that PJM has determined is necessary.	Medium	2018	Not Adopted	Archived
Planning	The MMU recommends that the question of whether Capacity Injection Rights (CIRs) should persist after the retirement of a unit be addressed. Even if the treatment of CIRs remains unchanged, the rules need to ensure that incumbents cannot exploit control of CIRs to block or postpone entry of competitors.	Low	2013	Not Adopted	Archived
Planning	The MMU recommends that barriers to entry be address 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 and reflect the uncertainty and resultant risks in the cost of new entry used to establish the capacity market demand curve in RPM.	Low	2012	Not Adopted	Archived
Planning	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.	Medium	2013	Partially Adopted	Archived
Planning	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.	Medium	2014	Partially Adopted	Archived
Planning	The MMU recommends outsourcing interconnection studies to an independent party to avoid 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.	Low	2013	Not Adopted	Archived
Planning	The MMU recommends that PJM modify the rules governing the market efficiency process benefit/cost analysis so that competing projects with different in service dates are evaluated on a symmetric, comparable basis.	Medium	2018	Not Adopted	Assessment
Planning	The MMU recommends that PJM enhance the transparency and queue management process for merchant 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 merchant transmission.	Medium	2015	Not Adopted	Archived
Planning	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.	Low	2001	Not Adopted	Archived
Planning	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.	Low	2013	Not Adopted	Archived

	ARCHIVED				
Section	2018 Recommendation	Priority	Year Reported	Status	PJM Status 2019
Planning	The MMU recommends that PJM establish fair terms of access to rights of way and property, such as at substations, in order to remove barriers to entry and permit competition between incumbent transmission providers and merchant transmission providers in the RTEP.	Medium	2014	Not Adopted	Archived
Planning	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.	Low	2013	Not Adopted	Archived
Planning	The MMU recommends that rules be implemented to require that project cost caps on new transmission projects be part of the evaluation of competing projects.	Medium	2015	Not Adopted	Archived
Planning	The MMU recommends consideration of changing the minimum distribution factor in the allocation from 0.01 to 0.00 and adding a threshold minimum usage impact on the line.	Medium	2015	Not Adopted	Archived
Planning	The MMU recommends that PJM reevaluate all transmission outage tickets as on time or late if they were new requests when an outage is rescheduled and apply the standard rules for late submissions to any such outages.	Low	2014	Not Adopted	Archived
Planning	The MMU recommends that PJM draft a clear definition of the congestion analysis required for transmission outage requests to include in Manual 3 after appropriate review.	Low	2015	Not Adopted	Archived
Planning	The MMU recommends that PJM modify the rules to reduce or eliminate the approval of late outage requests submitted or rescheduled after the FTR auction bidding opening date.	Low	2015	Not Adopted	Archived
Planning	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.	Low	2015	Not Adopted	Archived
FTRs & ARRs	The MMU recommends that all FTR auction revenue be distributed to ARR holders monthly, regardless of FTR funding levels.	High	2015	Not Adopted	Archived
FTRs & ARRs	The MMU recommends that FTR auction revenues not be used to buy counter flow FTRs for the purpose of improving FTR payout ratios.	High	2015	Not Adopted	Archived
FTRs & ARRs	The MMU recommends that all historical generation to load paths be eliminated as a basis for allocating ARRs.	High	2015	Partially Adopted	Archived
FTRs & ARRs	The MMU recommends that PJM eliminate portfolio netting to eliminate cross subsidies among FTR market participants.	High	2012	Not Adopted *Rejected by FERC*	Archived
FTRs & ARRs	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.	High	2012	Not Adopted	Archived
FTRs & ARRs	The MMU recommends that PJM eliminate geographic cross subsidies.	High	2013	Not Adopted	Archived
FTRs & ARRs	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.	Low	2011	Not Adopted	Archived
FTRs & ARRs	The MMU recommends that PJM reduce FTR sales on paths with persistent over allocation of FTRs including clear rules for what defines persistent over allocation and how the reduction will be applied.	High	2013	Partially Adopted	Archived
FTRs & ARRs	The MMU recommends that the direct customer request approach for creating and allocating IARR should be eliminated from PJM's tariff.	Low	2018	Not Adopted	Archived