State of the Market Report for PJM

Volume 2: Detailed Analysis

Monitoring Analytics, LLC
Independent Market Monitor for PJM

2018

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Preface

The PJM Market Monitoring Plan provides:

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

Accordingly, Monitoring Analytics, LLC, which serves as the Market Monitoring Unit (MMU) for PJM Interconnection, L.L.C. (PJM),[2] and is also known as the Independent Market Monitor for PJM (IMM), submits this *2018 State of the Market Report for PJM*.[3]

1 PJM Open Access Transmission Tariff (OATT) Attachment M (PJM Market Monitoring Plan) § VI.A. Capitalized terms used herein and not otherwise defined have the meaning provided in the OATT, PJM Operating Agreement, PJM Reliability Assurance Agreement or other tariffs that PJM has on file with the Federal Energy Regulatory Commission (FERC or Commission).

2 OATT Attachment M.

3 All references to this report should refer to the source as Monitoring Analytics, LLC, and should include the complete name of the report: *2018 State of the Market Report for PJM*.

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Introduction

2018 in Review

The goal of competition is to provide customers wholesale power at the lowest possible price, but no lower. The results of the energy market were competitive in 2018. The PJM markets work, even if not perfectly. The results of the base capacity auction run in 2018 for 2021/2022 were not competitive and the underlying issues need to be addressed. The PJM markets bring customers the benefits of competition. But the PJM markets, and wholesale power markets in the U.S., face new challenges that potentially threaten the viability of competitive markets. It is the job of the MMU to defend competitive markets.

The basic design of both the energy market and the capacity market face significant uncertainty. PJM will soon make a filing challenging the fundamentals of the energy market design. PJM has made a filing to change the fundamentals of the capacity market design, which is pending at the Commission. PJM is expected to propose further changes to the capacity market design in the name of fuel security that are inconsistent with the competitive market design. PJM's energy market design proposal will break the tight link between energy and capacity markets that has been essential to the success of the PJM market design.

PJM is not an energy only market. Revenue adequacy in PJM results from the interactions of the energy and capacity markets. PJM does not require a dramatic administrative expansion of the Operating Reserve Demand Curve (ORDC) to increase energy market revenues or provide revenue adequacy. Energy only markets are not more competitive than or conceptually preferable to markets with both energy and capacity markets. ORDCs are more administrative and more subjective than capacity markets. Rather than alter prices through an administrative scarcity adder from the ORDC, PJM should focus on fundamental improvements to energy market efficiency including efficiency improvements to the market software used to commit resources, dispatch resources, mitigate market power, and calculate uplift payments.

In order to attract and retain adequate resources for the reliable operation of the energy market, revenues from PJM energy, ancillary services and capacity markets must be adequate for those resources. That adequacy requires a capacity market. The capacity market plays the essential role of equilibrating the revenues necessary to incent competitive entry and exit of the resources needed for flexibility and reliability, given that the revenues from the energy market are most directly affected by nonmarket sources. It is essential that the equilibrating role of the capacity market not be weakened or eliminated.

Energy prices in PJM are not too low. There is no evidence to support the need for a significant change to the level of energy market revenues. The objective of efficient short run price signals in the energy market is to minimize system production costs, not to minimize uplift or to ensure a predefined level of revenues in the energy market. The market design issue that should be addressed directly is scarcity pricing, including the impact of operator actions on scarcity. Current energy and reserve prices do not reflect market conditions when the market is tight and when scarcity exists. Rather than raising prices in most hours as the ORDC would do, it would make more sense to directly incorporate the operators' demand for additional MW in the reserve demand curves and to implement scarcity pricing when there is actual scarcity.

One of the benefits of competitive power markets is that changes in input prices and changes in the balance of supply and demand are reflected immediately in energy prices. PJM real-time energy market prices increased significantly in 2018 compared to 2017. The load-weighted, average real-time LMP was 23.4 percent higher in 2018 than in 2017, $38.24 per MWh versus $30.99 per MWh.

Net revenue from the energy and capacity markets is a key measure of overall market performance as well as a measure of the incentive to invest in new generation to serve PJM markets. Net revenues increased for all unit types in 2018. In 2018, average energy market net revenues increased by 39 percent for a new combustion turbine (CT), 48 percent for a new combined cycle (CC), 138 percent for a new coal plant (CP), 32 percent for a new nuclear plant (NP), 255 percent for a new diesel (DS), 24 percent for a new on shore wind installation, and 10 percent for a new solar installation compared to 2017.

The PJM energy market remains fuel diverse. In 2018, natural gas-fired energy output exceeded coal-fired energy output and the fuel diversity index increased. The market provides incentive for entry and for exit. The MMU's forward looking analysis shows that 12,017 MW of coal and 2,937 MW of nuclear capacity are at risk of retirement. Based on public data about unit costs, and on forward prices for energy and known forward prices for capacity, three of 18 nuclear plants in PJM would not cover their annual avoidable costs over the next three years (2019 through 2021). The three plants are Davis Besse, Perry, and Three Mile Island. In May 2017, TMI requested deactivation in 2019. In March 2018, Davis Besse and Perry requested deactivation in 2021. All three plants are single unit sites which have higher operating costs per MWh than multiple unit plants.

Net revenues for coal plants and for nuclear power plants increased significantly in 2018 as a result of higher LMPs. But there are some coal power plants and nuclear power plants in PJM that are not economic at expected levels of energy and capacity market clearing prices. The decisions on how to proceed belong to the owners of those plants. The fact that some plants are uneconomic does not call into question the fundamentals of PJM markets. Many generating plants have retired in PJM since the introduction of markets and many generating plants have been built since the introduction of markets.

The level of potential retirements does not imply a reliability issue in PJM and does not imply a fuel security issue in PJM. A comparison of the total units at risk and the current excess capacity in PJM suggests that, ignoring local reliability issues, the current and expected excess capacity is of the same order of magnitude as the units at risk. PJM had excess reserves of more than 9,000 MW on June 1, 2018, and will have excess reserves of almost 13,000 MW on June 1, 2019, based on current positions. There are currently 114,954 MW in the PJM generator interconnection queues. Based on historical completion rates, 21,015 MW of new generation in the queue are expected to go into service.

The wholesale power grid is clearly resilient. The focus should be on ensuring that ongoing policy initiatives affecting wholesale power markets, including those about resilience, are analyzed and addressed within a market framework. The real resilience question is whether the market construct itself is resilient. Can markets, and the market based regulatory construct, coexist with efforts to define and implement resilience and fuel security based on a planning rather than market approach? Can markets, and the market based regulatory construct, coexist with efforts to increase the role of renewable resources through nonmarket revenue? Can markets, and the market based regulatory construct, coexist with efforts to support specific uneconomic resources through nonmarket revenue? Can markets, and the market based regulatory construct, coexist with efforts to alter the efficient market design to create market revenue streams to favored technologies and fuel types?

Market solutions are neutral with respect to technology and energy source. Market solutions are different than engineering and planning solutions that administratively alter efficient market outcomes. The use of administrative constraints in market software to procure reserves or capacity beyond the demand expressed by customers and for different resources than demanded by customers is not a market solution, especially when administrative pricing distorts prices from the efficient level.

Fuel security is a legitimate concern and fuel security should be analyzed and addressed within the market framework. The interactions between the power industry and the gas industry business and regulatory models requires substantial rethinking. Issues of fuel security for gas fired units have a basis in the somewhat incompatible models. Those issues can and should be addressed in a manner that is consistent with the interests of participants in both the power industry and the gas industry. Arbitrary determinations of the risk associated with gas as a fuel should be avoided in the interests of a fuel neutral approach.

The markets solution must recognize the role of competitive markets and that competitive markets need internally consistent rules in order to provide the incentives necessary for the markets to work. It is essential that any approach to the PJM markets incorporate a consistent view of how the preferred market design is expected to provide competitive results in a sustainable market design over the long run. A sustainable market design means a market design that results in appropriate incentives to competitive market participants to retire units and to invest in new units over time such that reliability is ensured as a result of the functioning of the market. The MMU calls this approach the Sustainable Market Rule (SMR).

A sustainable competitive wholesale power market must recognize three salient structural elements: state nonmarket revenues for renewable energy; a significant level of generation resources subject to cost of service regulation; and the structure and performance of the existing market based generation fleet. The relatively recent provision of nonmarket revenues to specific uneconomic existing resources, primarily nuclear power plants, is also a fact, but this is rent seeking by resources owners and not a structural element of markets. Subsidies to specific resources that are uneconomic as a result of competition are an effort to reverse market outcomes with no commitment to a regulatory model and no attempt to mitigate negative impacts on competition. The unit specific subsidy model is inconsistent with the PJM market design and inconsistent with the market paradigm and constitutes a significant threat to both. The events of 2018 have demonstrated that subsidies are contagious but also that antivirals exist.

With a significant level of zero marginal cost resources, a core goal of a competitive market design should be to ensure that the resources required to provide flexibility and reliability receive appropriate competitive market incentives for entry and for ongoing investment and for exit when uneconomic. The capacity market plays a central role which cannot be played by arbitrary price increases based on a subjective ORDC. Price suppression below the competitive level in the capacity market should not be acceptable and is not consistent with a competitive market design. Harmonizing the relationship between increased zero marginal cost resources and additional resources required for flexibility and reliability means maintaining a capacity market design to account for these energy market impacts, clearly limiting the impact of nonmarket revenues on the capacity market and ensuring competitive outcomes in the capacity market and thus in the entire market.

Before market outcomes are rejected in favor of nonmarket choices, the capacity market should be permitted to work. The capacity market design should provide strong incentives for flexibility and reliability. The capacity market has not been permitted to reveal the underlying supply and demand fundamentals in prices. It is more critical than ever to get capacity market prices correct. A number of capacity market design elements resulted in a substantial suppression of capacity market prices for multiple years and prices were increased above the competitive level in the 2021/2022 base auction.

To the extent that there are shared broader goals related to PJM markets, they should also be addressed. If society determines that carbon is a pollutant with a negative value, a market approach to carbon is preferred to a technology or unit specific subsidy approach. Unit specific subsidies are not an efficient approach. Implementation of a carbon price is a market approach which would let market participants respond in efficient and innovative ways to the price signal rather than relying on planners to identify specific technologies or resources to be subsidized. It would be helpful to the states if PJM would offer to model the impact of various levels of carbon prices on the dispatch and economic viability of units in PJM and the associated flow of dollars to states in the form of carbon revenue. With this information, the states could determine whether there is a form of carbon pricing and carbon revenue distribution that all the states could agree to.

The PJM markets and PJM market participants from all sectors face significant challenges. PJM and its market participants will need to continue to work constructively to address these challenges to ensure the continued effectiveness of PJM markets.

PJM Market Summary Statistics

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

Table 1-1 PJM Market Summary Statistics: 2017 and 2018[1]

	2017	2018	Percent Change
Average Hourly Load (MW)	86,618	90,307	4.3%
Average Hourly Generation (MW)	90,945	94,236	3.6%
Peak Load (MW)	142,387	147,042	3.3%
Installed Capacity at December 31 (MW)	183,882	185,952	1.1%
Load Weighted Average Real Time LMP ($/MWh)	$30.99	$38.24	23.4%
Total Congestion Costs ($ Million)	$697.59	$1,309.90	87.8%
Total Uplift Charges ($ Million)	$126.95	$198.52	56.4%
Total PJM Billing ($ Billion)	$40.17	$49.79	23.9%

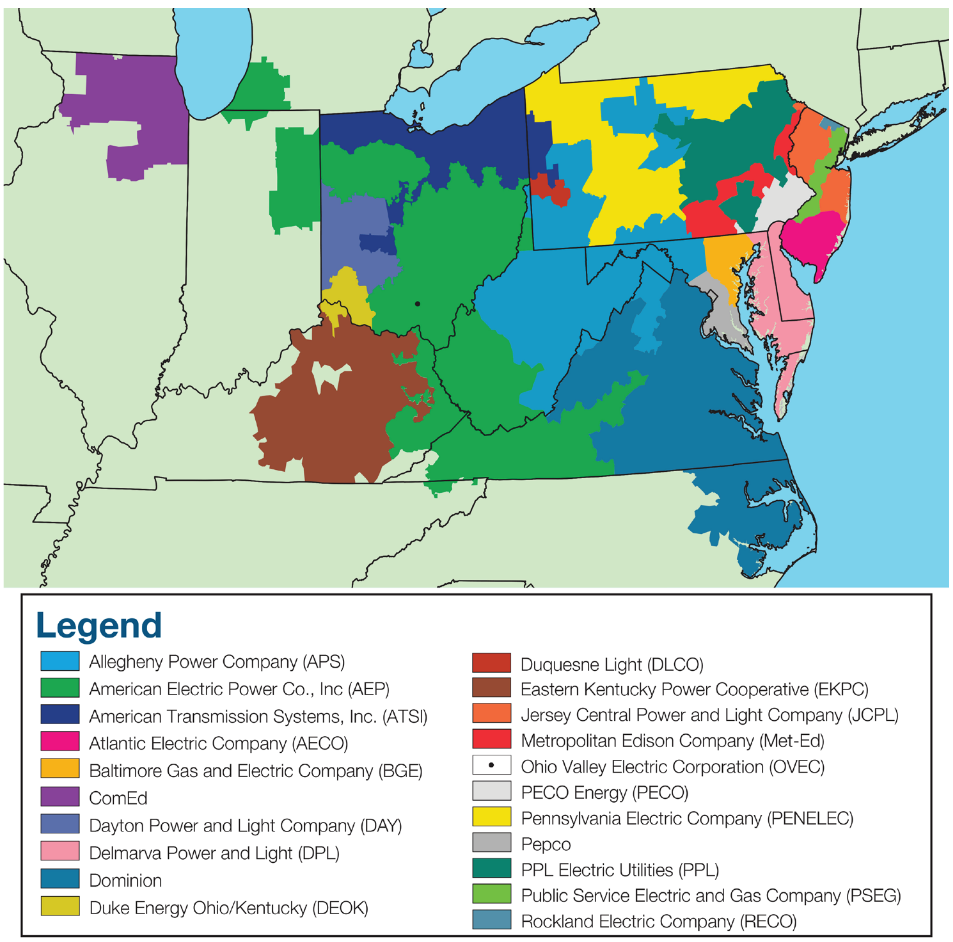
1 The load reported in this table is the accounting load plus net withdrawals at generator buses. The average hourly accounting load is reported in Section 3, "Energy Market."

PJM Market Background

The PJM Interconnection, L.L.C. (PJM) operates a centrally dispatched, competitive wholesale electric power market that, as of December 31, 2018, had installed generating capacity of 185,952 megawatts (MW) and 1,032 members including market buyers, sellers and traders of electricity in a region including more than 65 million people in all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia and the District of Columbia (Figure 1-1).[2 3 4]

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

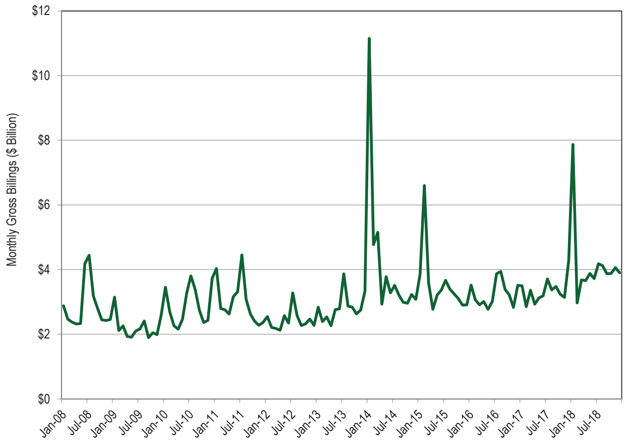
Figure 1-1 PJM's footprint and its 21 control zones



In 2018, PJM had total billings of $49.79 billion, an increase of 23.9 percent from $40.17 billion in 2017 (Figure 1-2).[5] The 2018 total is the second largest total annual billing amount in PJM history, almost matching the $50.04 billion in billings from 2014. The 2014 and 2018 totals were both affected by cold January weather.

2 See PJM. "Member List," which can be accessed at: <http://pjm.com/about-pjm/member-services/member-list.aspx>.
3 See PJM. "Who We Are," which can be accessed at: <http://pjm.com/about-pjm/who-we-are.aspx>.
4 See the *2018 State of the Market Report for PJM*, Volume 2, Appendix A:"PJM Geography" for maps showing the PJM footprint and its evolution prior to 2019.
5 Monthly and year to date billing values are provided by PJM.

Figure 1-2 PJM reported monthly billings ($ Billion): 2008 through 2018



PJM operates the Day-Ahead Energy Market, the Real-Time Energy Market, the Reliability Pricing Model (RPM) Capacity Market, the Regulation Market, the Synchronized Reserve Market, the Day-Ahead Scheduling Reserve (DASR) Market and the Financial Transmission Rights (FTRs) Markets.

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

Conclusions

This report assesses the competitiveness of the markets managed by PJM in 2018, including market structure, participant behavior and market performance. This report was prepared by and represents the analysis of the Independent Market Monitor for PJM, also referred to as the Market Monitoring Unit or MMU.

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

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

Market structure refers to the cost, demand, and ownership structure of the market. The three pivotal supplier (TPS) test is the most relevant measure of market structure because it accounts for the ownership of assets and the relationship among the pattern of ownership, the resource costs, and the market demand using actual market conditions with both temporal and geographic granularity. Market shares and the related Herfindahl-Hirschman Index (HHI) are also measures of market structure.

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

6 See also the *2018 State of the Market Report for PJM*, Volume 2, Appendix B: "PJM Market Milestones."

7 Analysis of 2018 market results requires comparison to prior years. During calendar years 2004 and 2005, PJM conducted the phased integration of five control zones: ComEd, American Electric Power (AEP), The Dayton Power & Light Company (DAY), Duquesne Light Company (DLCO) and Dominion. In June 2011, PJM integrated the American Transmission Systems, Inc. (ATSI) Control Zone. In January 2012, PJM integrated the Duke Energy Ohio/Kentucky (DEOK) Control Zone. In June 2013, PJM integrated the Eastern Kentucky Power Cooperative (EKPC). In December 2018, PJM integrated the Ohio Valley Electric Corporation (OVEC.) By convention, control zones bear the name of a large utility service provider working within their boundaries. The nomenclature applies to the geographic area, not to any single company. For additional information on the integrations, their timing and their impact on the footprint of the PJM service territory prior to 2019, see *2018 State of the Market Report for PJM*, Volume 2, Appendix A: "PJM Geography."

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

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

The MMU concludes for 2018:

Energy Market Conclusion

Table 1-2 The Energy Market results were competitive

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

- The aggregate market structure was evaluated as partially competitive because the aggregate market power test based on pivotal suppliers indicates that the aggregate day-ahead market structure was not competitive on every day. The hourly HHI (Herfindahl-Hirschman Index) results indicate that the PJM energy market in 2018 was unconcentrated by FERC HHI standards in 94 percent of market hours and moderately concentrated in six percent of market hours. Average HHI was 840 with a minimum of 624 and a maximum of 1242 in 2018. The PJM energy market peaking segment of supply was highly concentrated. The fact that the average HHI is in the unconcentrated range and the maximum hourly HHI is in the moderately concentrated range does not mean that the aggregate market was competitive in all hours. As demonstrated for the day-ahead market, it is possible to have pivotal suppliers in the aggregate market even when the HHI level is not in the highly concentrated range. It is possible to have an exercise of market power even when the HHI level is not in the highly concentrated range. The number of pivotal suppliers in the energy market is a more precise measure of structural market power than the HHI. The HHI is not a definitive measure of structural market power.
- The local market structure was evaluated as not competitive due to the highly concentrated ownership of supply in local markets created by transmission constraints and local reliability issues. The results of the three pivotal supplier (TPS) test, used to test local market structure, indicate the existence of market power in local markets created by transmission constraints. The local market performance is competitive as a result of the application of the TPS test. While transmission constraints create the potential for the exercise of local market power, PJM's application of the three pivotal supplier test identified local market power and resulted in offer capping to force competitive offers, correcting for structural issues created by local transmission constraints. There are, however, identified issues with the application of market power mitigation to resources whose owners fail the TPS test that need to be addressed because unit owners can exercise market power even when they fail the TPS test.
- Participant behavior was evaluated as competitive because the analysis of markup shows that marginal units generally make offers at, or close to, their marginal costs in both Day-Ahead and Real-Time Energy Markets, although the behavior of some participants both routinely and during periods of high demand represents economic withholding and the markups of those participants affected LMP.
- Market performance was evaluated as competitive because market results in the energy market reflect the outcome of a competitive market, as PJM prices are set, on average, by marginal units operating at, or close to, their marginal costs in both Day-Ahead and Real-Time Energy Markets, although high markups for some marginal units did affect prices.
- Market design was evaluated as effective because the analysis shows that the PJM energy market resulted in competitive market outcomes. In general,

PJM's energy market design provides incentives for competitive behavior and results in competitive outcomes. In local markets, where market power is an issue, the market design identifies market power and causes the market to provide competitive market outcomes in most cases although issues with the implementation of market power mitigation and development of cost-based offers remain. The role of UTCs in the Day-Ahead Energy Market continues to cause concerns.

- PJM markets are designed to promote competitive outcomes derived from the interaction of supply and demand in each of the PJM markets. Market design itself is the primary means of achieving and promoting competitive outcomes in PJM markets. One of the MMU's primary goals is to identify actual or potential market design flaws.[8] The approach to market power mitigation in PJM has focused on market designs that promote competition (a structural basis for competitive outcomes) and on limiting market power mitigation to instances where the market structure is not competitive and thus where market design alone cannot mitigate market power. In the PJM energy market, this occurs primarily in the case of local market power. When a transmission constraint creates the potential for local market power, PJM applies a structural test to determine if the local market is competitive, applies a behavioral test to determine if generator offers exceed competitive levels and applies a market performance test to determine if such generator offers would affect the market price.[9] There are, however, identified issues with the application of market power mitigation to resources whose owners fail the TPS test that can result in the exercise of local market power even when market power mitigation rules are applied. These issues need to be addressed. There are issues related to the definition of gas costs includable in energy offers that need to be addressed. There are issues related to the level of variable operating and maintenance expense includable in energy offers that need to be addressed. There are currently no market power mitigation rules in place that limit the ability to exercise market power when aggregate market conditions are tight and there are pivotal suppliers in the aggregate market. Aggregate market power needs to be addressed. Now that generators are allowed to modify offers hourly, market design must reflect appropriate incentives for competitive behavior, the application of local market power mitigation needs to be fixed, the definition of a competitive offer needs to be fixed, and aggregate market power mitigation rules need to be developed. The importance of these issues is amplified by the new rules permitting cost-based offers in excess of $1,000 per MWh.

Capacity Market Conclusion

Table 1-3 The Capacity Market results were not competitive

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

- The aggregate market structure was evaluated as not competitive. For almost all auctions held from 2007 to the present, the PJM region failed the three pivotal supplier test (TPS), which is conducted at the time of the auction.[10] Structural market power is endemic to the capacity market.
- The local market structure was evaluated as not competitive. For almost every auction held, all LDAs have failed the TPS test, which is conducted at the time of the auction.[11]
- Participant behavior was evaluated as not competitive. Market power mitigation measures were applied when the Capacity Market Seller failed the market power test for the auction, the submitted sell offer exceeded the defined offer cap, and the submitted sell offer, absent mitigation, would increase the market clearing price. But the net CONE times B offer cap under the capacity performance design, in the absence of performance assessment hours, exceeds the competitive level and should be reevaluated for each BRA. In the 2021/2022 RPM Base Residual Auction, some participants'

8 OATT Attachment M (PJM Market Monitoring Plan).
9 The market performance test means that offer capping is not applied if the offer does not exceed the competitive level and therefore market power would not affect market performance.

10 In the 2008/2009 RPM Third Incremental Auction, 18 participants in the RTO market passed the TPS test. In the 2018/2019 RPM Second Incremental Auction, 35 participants in the RTO market passed the test.
11 In the 2012/2013 RPM Base Residual Auction, six participants included in the incremental supply of EMAAC passed the TPS test. In the 2014/2015 RPM Base Residual Auction, seven participants in the incremental supply in MAAC passed the TPS test.

offers were above the competitive level. The MMU recognizes that these market participants followed the capacity market rules by offering at less than the stated offer cap of Net CONE times B. But Net CONE times B is not a competitive offer when the expected number of performance assessment intervals is zero or a very small number and the non-performance charge rate is defined as Net CONE/30. Under these circumstances, a competitive offer, under the logic defined in PJM's capacity performance filing, is net ACR. That is the way in which most market participants offered in this and prior capacity performance auctions.

- Market performance was evaluated as not competitive. Although structural market power exists in the Capacity Market, a competitive outcome can result from the application of market power mitigation rules. The outcome of the 2021/2022 RPM Base Residual Auction was not competitive as a result of participant behavior which was not competitive, specifically offers which exceeded the competitive level.
- Market design was evaluated as mixed because while there are many positive features of the Reliability Pricing Model (RPM) design and the capacity performance modifications to RPM, there are several features of the RPM design which still threaten competitive outcomes. These include the definition of DR which permits inferior products to substitute for capacity, the replacement capacity issue, the definition of unit offer parameters, the inclusion of imports which are not substitutes for internal capacity resources, and the definition of the default offer cap.

Tier 2 Synchronized Reserve Market Conclusion

Table 1-4 The tier 2 synchronized reserve market results were competitive

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

- The tier 2 synchronized reserve market structure was evaluated as not competitive because of high levels of supplier concentration.
- Participant behavior was evaluated as competitive because the market rules require competitive, cost-based offers.
- Market performance was evaluated as competitive because the interaction of participant behavior with the market design results in competitive prices.
- Market design was evaluated as mixed. Market power mitigation rules result in competitive outcomes despite high levels of supplier concentration. However, tier 1 reserves are inappropriately compensated when the nonsynchronized reserve market clears with a nonzero price.

Day-Ahead Scheduling Reserve Market Conclusion

Table 1-5 The day-ahead scheduling reserve market results were competitive

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

- The day-ahead scheduling reserve market structure was evaluated as not competitive because market participants failed the three pivotal supplier test in 9.8 percent of all cleared hours in 2018.
- Participant behavior was evaluated as mixed because while most offers were equal to marginal costs, a significant proportion of offers reflected economic withholding.
- Market performance was evaluated as competitive because there were adequate offers in every hour to satisfy the requirement and the clearing prices reflected those offers, although there is concern about offers above the competitive level affecting prices. Offers above $0.00 were part of the clearing price in 96.4 percent of cleared hours when the clearing price was above $0.
- Market design was evaluated as mixed because the DASR product does not include performance obligations. Offers should be based on opportunity cost only, to ensure competitive outcomes and that market power cannot be exercised.

Regulation Market Conclusion

Table 1-6 The regulation market results were competitive

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

- The regulation market structure was evaluated as not competitive because the PJM Regulation Market failed the three pivotal supplier (TPS) test in 81.7 percent of the hours in 2018.
- Participant behavior in the PJM Regulation Market was evaluated as competitive for 2018 because market power mitigation requires competitive offers when the three pivotal supplier test is failed and there was no evidence of generation owners engaging in noncompetitive behavior.
- Market performance was evaluated as competitive, despite significant issues with the market design.
- Market design was evaluated as flawed. The market design has failed to correctly incorporate a consistent implementation of the marginal benefit factor in optimization, pricing and settlement. The market results continue to include the incorrect definition of opportunity cost. The result is significantly flawed market signals to existing and prospective suppliers of regulation.

FTR Auction Market Conclusion

Table 1-7 The FTR auction markets results were competitive

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

- Market structure was evaluated as partially competitive because while purchasing FTRs in the FTR Auction is voluntary, issues have been identified with the assignment of system capability between ARRs and FTRs as well as the accuracy of modeling in the Long Term FTR Auctions. The ownership structure of Long Term FTRs, particularly the three year product, is highly concentrated.
- Participant behavior was evaluated as partially competitive based on the behavior of GreenHat Energy, LLC.
- Market performance was evaluated as competitive because it reflected the interaction between participant demand behavior and the expected system capability that PJM made available for sale as FTRs. It is not clear, in a competitive market, why FTR purchases by financial entities remain persistently profitable.
- Market design was evaluated as flawed because there are significant flaws with the basic ARR/FTR design. The market design is not an efficient or effective way to ensure that all congestion revenues are returned to load. ARR holders' rights to congestion revenues are not defined clearly enough. ARR holders cannot determine the price at which they are willing to sell rights to congestion revenue. Ongoing PJM subjective intervention in the FTR market that affects market fundamentals is also an issue.

Role of MMU

FERC assigns three core functions to MMUs: reporting, monitoring and market design.[12] These functions are interrelated and overlap. The PJM Market Monitoring Plan establishes these functions, providing that the MMU is responsible for monitoring: compliance with the PJM Market Rules; actual or potential design flaws in the PJM Market Rules; structural problems in the PJM Markets that may inhibit a robust and competitive market; the actual or potential exercise of market power or violation of the market rules by a Market Participant; PJM's implementation of the PJM Market Rules or operation of the PJM Markets; and such matters as are necessary to prepare reports.[13]

Reporting

The MMU performs its reporting function primarily by issuing and filing annual and quarterly state of the market reports; regular reports on market issues; such as RPM auction reports; reports responding to requests from regulators and other authorities; and ad hoc reports on specific topics. The state of the market reports provide a comprehensive analysis of market structure, participant conduct and market performance for the PJM markets.

12 18 CFR § 35.28(g)(3)(ii); see also *Wholesale Competition in Regions with Organized Electric Markets*, Order No. 719, FERC Stats. & Regs. ¶31,281 (2008) ("Order No. 719"), *order on reh'g*, Order No. 719-A, FERC Stats. & Regs. ¶31,292 (2009), *reh'g denied*, Order No. 719-B, 129 FERC ¶ 61,252 (2009).

13 OATT Attachment M § IV; 18 CFR § 1c.2.

State of the market reports and other reports are intended to inform PJM, the PJM Board, FERC, other regulators, other authorities, market participants, stakeholders and the general public about how well PJM markets achieve the competitive outcomes necessary to realize the goals of regulation through competition, and how the markets can be improved.

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

Monitoring

To perform its monitoring function, the MMU screens and monitors the conduct of Market Participants under the MMU's broad purview to monitor, investigate, evaluate and report on the PJM Markets.[14] The MMU has direct, confidential access to the FERC.[15] The MMU may also refer matters to the attention of state commissions.[16]

The MMU monitors market behavior for violations of FERC Market Rules and PJM Market Rules, including the actual or potential exercise of market power.[17] The MMU will investigate and refer "Market Violations," which refer to any of "a tariff violation, violation of a Commission-approved order, rule or regulation, market manipulation, or inappropriate dispatch that creates substantial concerns regarding unnecessary market inefficiencies..."[18] [19] [20] The MMU also monitors PJM for compliance with the rules, in addition to market participants.[21]

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

If the cost-based offer does not accurately reflect short run marginal cost, the market power mitigation process does not ensure competitive pricing in PJM markets. The MMU evaluates the fuel cost policy for every unit as well as the other inputs to cost-based offers. PJM Manual 15 does not clearly or accurately describe the short run marginal cost of generation. Manual 15 should be replaced with a straightforward description of the components of cost offers based on short run marginal costs and the correct calculation of cost offers. The MMU evaluates every offer in each capacity market (RPM) auction using data submitted to the MMU through web-based data input systems developed by the MMU.[22]

The MMU also reviews operational parameter limits included with unit offers, evaluates compliance with the requirement to offer into the energy and capacity markets, evaluates the economic basis for unit retirement

14 OATT Attachment M § IV.

15 OATT Attachment M § IV.K.3.

16 OATT Attachment M § IV.H.

17 OATT § I.1 ("FERC Market Rules" mean the market behavior rules and the prohibition against electric energy market manipulation codified by the Commission in its Rules and Regulations at 18 CFR §§ 1c.2 and 35.37, respectively; the Commission-approved PJM Market Rules and any related proscriptions or any successor rules that the Commission from time to time may issue, approve or otherwise establish… "PJM Market Rules" mean the rules, standards, procedures, and practices of the PJM Markets set forth in the PJM Tariff, the PJM Operating Agreement, the PJM Reliability Assurance Agreement, the PJM Consolidated Transmission Owners Agreement, the PJM Manuals, the PJM Regional Practices Document, the PJM-Midwest Independent Transmission System Operator Joint Operating Agreement or any other document setting forth market rules.")

18 The FERC defines manipulation as engaging "in any act, practice, or course of business that operates or would operate as a fraud or deceit upon any entity." 18 CFR § 1c.2(a)(3). Manipulation may involve behavior that is consistent with the letter of the rules, but violates their spirit. An example is market behavior that is economically meaningless, such as equal and opposite transactions, which may entitle the transacting party to a benefit associated with volume. Unlike market power or rule violations, manipulation must be intentional. The MMU must build its case, including an inference of intent, on the basis of market data.

19 OATT § I.1.

20 The MMU has no prosecutorial or enforcement authority. The MMU notifies the FERC when it identifies a significant market problem or market violation. OATT Attachment M § IV.I.1. If the problem or violation involves a market participant, the MMU discusses the matter with the participant(s) involved and analyzes relevant market data. If that investigation produces sufficient credible evidence of a violation, the MMU prepares a formal referral and thereafter undertakes additional investigation of the specific matter only at the direction of FERC staff. *Id.* If the problem involves an existing or proposed law, rule or practice that exposes PJM markets to the risk that market power or market manipulation could compromise the integrity of the markets, the MMU explains the issue, as appropriate, to the FERC, state regulators, stakeholders or other authorities. The MMU may also participate as a party or provide information or testimony in regulatory or other proceedings.

21 OATT Attachment M § IV.C.

22 OATT Attachment M–Appendix § II.E.

requests and evaluates and compares offers in the Day-Ahead and Real-Time Energy Markets.[23] [24] [25] [26]

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

The PJM Markets monitored by the MMU include market related procurement processes conducted by PJM, such as for Black Start resources included in the PJM system restoration plan.[27] [28]

The MMU also monitors transmission planning, interconnections and rules for vertical market power issues, and with the introduction of competitive transmission development policy in Order No. 1000, horizontal market power issues.[29]

Market Design

In order to perform its role in PJM market design, the MMU evaluates existing and proposed PJM Market Rules and the design of the PJM Markets.[30] The MMU initiates and proposes changes to the design of such markets or the PJM Market Rules in stakeholder or regulatory proceedings.[31] In support of this function, the MMU engages in discussions with stakeholders, State Commissions, PJM Management, and the PJM Board; participates in PJM stakeholder meetings or working groups regarding market design matters; publishes proposals, reports or studies on such market design issues; and makes filings with the Commission on market design issues.[32] The MMU also recommends changes to the PJM Market Rules to the staff of the Commission's Office of Energy Market Regulation, State Commissions, and the PJM Board.[33] The MMU may provide in its annual, quarterly and other reports "recommendations regarding any matter within its purview."[34]

New Recommendations

Consistent with its core function to "[e]valuate existing and proposed market rules, tariff provisions and market design elements and recommend proposed rule and tariff changes,"[35] the MMU recommends specific enhancements to existing market rules and implementation of new rules that are required for competitive results in PJM markets and for continued improvements in the functioning of PJM markets.

In this *2018 State of the Market Report for PJM*, the MMU includes 36 new recommendations made for 2018, 17 of which are new in this 2018 annual report.[36] [37]

New Recommendations from Section 3, 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. (Priority: Medium. First reported Q3, 2018. Status: Not adopted.)
- The MMU recommends that PJM clearly define the business rules that apply to the unit specific parameter adjustment process, including PJM's implementation of the tariff rules in the PJM manuals to ensure market sellers know the requirements for their resources. (Priority: Low. First reported Q3, 2018. Status: Not adopted.)

23 OATT Attachment M–Appendix § II.B.
24 OATT Attachment M–Appendix § II.C.
25 OATT Attachment M–Appendix § IV.
26 OATT Attachment M–Appendix § VII.
27 OATT Attachment M–Appendix § II(p).
28 OATT Attachment M–Appendix § III.
29 OA Schedule 6 § 1.5.
30 OATT Attachment M § IV.D.
31 *Id.*
32 *Id.*
33 *Id.*
34 OATT Attachment M § VI.A.
35 18 CFR § 35.28(g)(3)(ii)(A); see also OATT Attachment M § IV.D.
36 New recommendations include all MMU recommendations that were reported for the first time in the *2018 State of the Market Report for PJM* or in any of the three quarterly state of the market reports that were published in 2018.
37 For a complete list of MMU recommendations, see the *2018 State of the Market Report for PJM*, Vol 2, Section 2, Recommendations.

- 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 as the basis for Fuel Cost Policies but should not be required. (Priority: Low. First reported Q1, 2018. Status: Not adopted.)
- 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. (Priority: Low. First reported Q1, 2018. Status: Not adopted.)
- The MMU recommends that PJM update the tariff to clarify that all generation resources are subject to unit specific parameter limits on their cost-based offers using the same standard and process as capacity performance capacity resources. (Priority: Medium. New recommendation. Status: Not adopted.)
- 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. (Priority: Medium. New recommendation. Status: Not adopted.)
- 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. (Priority: High. New recommendation. Status: Not adopted.)

New Recommendations from Section 4, Energy Uplift

- The MMU recommends that uplift should only be paid based on operating parameters that reflect the flexibility of the benchmark new entrant unit (CONE unit) in the PJM Capacity Market. (Priority: High. First reported Q1, 2018. Status: Not adopted.)
- The MMU recommends eliminating the use of intraday segments to define eligibility for uplift payments and returning to evaluating the need for uplift on a daily, 24 hours, basis. (Priority: High. First reported Q1, 2018. Status: Not adopted.)
- The MMU recommends that PJM pay uplift based on the offer at the lower of the actual unit output or the dispatch signal MW. (Priority: Medium. First reported Q1, 2018. Status: Not adopted.)
- 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. (Priority: Medium. First reported Q1, 2018. Status: Not adopted.)
- 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 (Priority: Medium. New recommendation. Status: Not adopted.)

New Recommendation from Section 5, 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. (Priority: Medium. First reported Q3, 2018. Status: Not adopted.)

New Recommendations from Section 6, 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. (Priority: Medium. New recommendation. Status: Not adopted.)
- The MMU recommends that 30 minute pre-emergency and emergency demand response be considered to be 30 minute reserves. (Priority: Medium. New recommendation. Status: Not adopted.)
- 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 with the existing lag. (Priority: Medium. New recommendation. Status: Not adopted.)

New Recommendations from Section 8, Environmental and Renewable Energy Regulations

- The MMU recommends that the Commission reconsider its disclaimer of jurisdiction over RECs markets because, given market changes since that decision, it is clear that RECs materially affect jurisdictional rates. (Priority: High. New recommendation. Status: Not adopted.)
- 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. (Priority: Medium. New recommendation. Status: Not adopted.)
- The MMU recommends that jurisdictions with a renewable portfolio standard make the price and quantity data on supply and demand more transparent. (Priority: Low. First reported Q2, 2018. Status: Not adopted.)

New Recommendations from Section 10, Ancillary Service Markets

- The MMU recommends that the $7.50 margin be eliminated from the definition of the cost of tier 2 synchronized reserve because it is a markup and not a cost. (Priority: Medium. First reported Q3, 2018. Status: Not adopted.)
- 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. (Priority: Medium. First reported Q3, 2018. Status: Not adopted.)
- The MMU recommends that aggregation not be permitted to offset unit specific penalties for failure to respond to a synchronized reserve event. (Priority: Medium. First reported Q3, 2018. Status: Not adopted.)
- The MMU recommends that offers in the DASR Market be based on opportunity cost only in order to eliminate market power. (Priority: Low. First reported 2009. Modified Q3, 2018. Status: Not adopted.)
- The MMU recommends that payments for reactive capability, if continued, be based on the 0.90 power factor that PJM has determined is necessary. (Priority: Medium. First reported Q3, 2018. Status: Not adopted.)
- The MMU recommends that PJM eliminate the use of Degree of Generator Performance (DGP) in the synchronized reserve market solution and improve the actual tier 1 estimate. If PJM continues to use DGP, DGP should be documented in PJM's manuals. (Priority: Medium. New recommendation. Status: Not adopted.)
- 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. (Priority: Medium. New recommendation. Status: Not adopted.)

New Recommendations from Section 12, Generation and Transmission 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. (Priority: Medium. First reported Q3, 2018. Status: Not adopted.)
- 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. (Priority: Low. New recommendation. Status: Not adopted.)
- 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. (Priority: Medium. New recommendation. Status: Not adopted.)

New Recommendations from Section 13, Financial Transmission and Auction Revenue Rights

- The MMU recommends that PJM continue to review the management of a defaulted member's FTR portfolio, including options other than liquidation. (Priority: High. First reported Q2, 2018. Status: Not adopted.)
- The MMU recommends that, under the current FTR design, all congestion revenue in excess of FTR target allocations be distributed to ARR holders on a monthly basis. (Priority: High. First reported Q1, 2018. Status: Not adopted.)
- The MMU recommends that the Long Term FTR product be eliminated. (Priority: High. First reported Q3, 2018. Status: Not adopted.)
- The MMU recommends that PJM continue to evaluate the bilateral indemnification rules and any asymmetries they may create. (Priority: Low. New recommendation. Status: Not adopted.)
- The MMU recommends that PJM examine the source and sink node combinations available in the FTR market, and to ensure they represent paths that may actually face congestion. (Priority: High. New recommendation. Status: Not adopted.)
- 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. (Priority: High. New recommendation. Status: Not adopted.)
- The MMU recommends that the direct customer request approach for creating and allocating IARR should be eliminated from PJM's tariff. (Priority: Low. New recommendation. Status: Not adopted.)

Total Price of Wholesale Power

The total price of wholesale power is the total price per MWh of purchasing wholesale electricity from PJM markets. The total price is an average price and actual prices vary by location. The total price includes the price of energy, capacity, ancillary services, and transmission service, administrative fees, regulatory support fees and uplift charges billed through PJM systems. Table 1-8 shows the average price, by component, for 2017 and 2018.

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

Components of Total Price

- The Energy component is the real time load weighted average PJM locational marginal price (LMP).
- The Capacity component is the average price per MWh of Reliability Pricing Model (RPM) payments.
- The Transmission Service Charges component is the average price per MWh of network integration charges, and firm and nonfirm point to point transmission service.[38]
- The Energy Uplift (Operating Reserves) component is the average price per MWh of day-ahead and balancing operating reserves and synchronous condensing charges.[39]
- The Reactive component is the average cost per MWh of reactive supply and voltage control from generation and other sources.[40]
- The Regulation component is the average cost per MWh of regulation procured through the PJM Regulation Market.[41]
- The PJM Administrative Fees component is the average cost per MWh of PJM's monthly expenses for a number of administrative services, including Advanced Control Center (AC^2) and OATT Schedule 9 funding of FERC, OPSI, CAPS and the MMU.
- The Transmission Enhancement Cost Recovery component is the average cost per MWh of PJM billed (and not otherwise collected through utility rates) costs for transmission upgrades and projects, including annual recovery for the TrAIL and PATH projects.[42]
- The Capacity (FRR) component is the average cost per MWh under the Fixed Resource Requirement (FRR) Alternative for an eligible LSE to satisfy its Unforced Capacity obligation.[43]

38 OATT §§ 13.7, 14.5, 27A & 34.
39 OA Schedules 1 §§ 3.2.3 & 3.3.3.
40 OATT Schedule 2 and OA Schedule 1 § 3.2.3B. The line item in Table 1-8 includes all reactive services charges.
41 OA Schedules 1 §§ 3.2.2, 3.2.2A, 3.3.2, & 3.3.2A; OATT Schedule 3.
42 OATT Schedule 12.
43 RAA Schedule 8.1.

- The Emergency Load Response component is the average cost per MWh of the PJM Emergency Load Response Program.[44]
- The Day-Ahead Scheduling Reserve component is the average cost per MWh of Day-Ahead scheduling reserves procured through the Day-Ahead Scheduling Reserve Market.[45]
- The Transmission Owner (Schedule 1A) component is the average cost per MWh of transmission owner scheduling, system control and dispatch services charged to transmission customers.[46]
- The Synchronized Reserve component is the average cost per MWh of synchronized reserve procured through the Synchronized Reserve Market.[47]
- The Black Start component is the average cost per MWh of black start service.[48]
- The RTO Startup and Expansion component is the average cost per MWh of charges to recover AEP, ComEd and DAY's integration expenses.[49]
- The NERC/RFC component is the average cost per MWh of NERC and RFC charges, plus any reconciliation charges.[50]
- The Economic Load Response component is the average cost per MWh of day ahead and real time economic load response program charges to LSEs.[51]
- The Transmission Facility Charges component is the average cost per MWh of Ramapo Phase Angle Regulators charges allocated to PJM Mid-Atlantic transmission owners.[52]
- The nonsynchronized reserve component is the average cost per MWh of non-synchronized reserve procured through the Non-Synchronized Reserve Market.[53]
- The Emergency Energy component is the average cost per MWh of emergency energy.[54]

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

Table 1-8 shows that Energy, Capacity and Transmission Charges are the three largest components of the total price per MWh of wholesale power, comprising 97.5 percent of the total price per MWh in 2018.

Table 1-8 Total price per MWh by category: 2017 and 2018[55] [56]

Category	2017 $/MWh	2017 ($ Millions)	2017 Percent of Total	2018 $/MWh	2018 ($ Millions)	2018 Percent of Total	Percent Change
Load Weighted Energy	$30.99	$23,513	58.2%	$38.24	$30,253	61.4%	23.4%
Capacity	$11.27	$8,552	21.2%	$13.01	$10,295	20.9%	15.5%
Capacity	$11.23	$8,524	21.1%	$12.97	$10,260	20.8%	15.5%
Capacity (FRR)	$0.00	$0	0.0%	$0.00	$0	0.0%	0.0%
Capacity (RMR)	$0.04	$28	0.1%	$0.04	$34	0.1%	17.1%
Transmission	$9.54	$7,242	17.9%	$9.47	$7,494	15.2%	(0.8%)
Transmission Service Charges	$8.83	$6,703	16.6%	$8.81	$6,966	14.1%	(0.3%)
Transmission Enhancement Cost Recovery	$0.64	$487	1.2%	$0.57	$454	0.9%	(10.6%)
Transmission Owner (Schedule 1A)	$0.10	$73	0.2%	$0.09	$74	0.2%	(3.0%)
Transmission Seams Elimination Cost Assignment (SECA)	($0.03)	($21)	(0.1%)	$0.00	$0	0.0%	(100.0%)
Transmission Facility Charges	$0.00	$0	0.0%	$0.00	$0	0.0%	0.0%
Ancillary	$0.77	$585	1.4%	$0.83	$654	1.3%	7.3%
Reactive	$0.43	$327	0.8%	$0.43	$342	0.7%	0.1%
Regulation	$0.14	$104	0.3%	$0.18	$145	0.3%	33.6%
Black Start	$0.09	$70	0.2%	$0.08	$65	0.1%	(10.7%)
Synchronized Reserves	$0.06	$42	0.1%	$0.06	$50	0.1%	14.7%
Non-Synchronized Reserves	$0.01	$7	0.0%	$0.02	$15	0.0%	106.4%
Day Ahead Scheduling Reserve (DASR)	$0.05	$35	0.1%	$0.05	$37	0.1%	2.0%
Administration	$0.52	$393	1.0%	$0.50	$399	0.8%	(2.8%)
PJM Administrative Fees	$0.48	$367	0.9%	$0.47	$371	0.8%	(2.9%)
NERC/RFC	$0.03	$24	0.1%	$0.03	$25	0.1%	(0.9%)
RTO Startup and Expansion	$0.00	$2	0.0%	$0.00	$2	0.0%	(3.2%)
Energy Uplift (Operating Reserves)	$0.14	$107	0.3%	$0.23	$186	0.4%	67.1%
Demand Response	$0.01	$5	0.0%	$0.01	$5	0.0%	(1.5%)
Load Response	$0.01	$5	0.0%	$0.01	$5	0.0%	(1.5%)
Emergency Load Response	$0.00	$0	0.0%	$0.00	$0	0.0%	0.0%
Emergency Energy	$0.00	$0	0.0%	$0.00	$0	0.0%	0.0%
Total Price	$53.24	$40,397	100.0%	$62.30	$49,285	100.0%	17.0%
Total Load (GWh)	758,775			791,093			4.3%
Total Billing ($ Billions)	$40.40			$49.29			22.0%

55 Note: The totals in this table include after the fact billing adjustments and may not match totals presented in past reports.

56 The total billing in this table does not match the PJM reported total billing due to differences in calculation methods. For example, PJM accounts for all adjustments in the month billed, whereas the totals presented in these tables account for those adjustments in the month for which the adjustment was applied.

Table 1-9 shows the inflation adjusted average price, by component, for 2017 and 2018. To obtain the inflation adjusted average prices, the individual components' prices are deflated using the US Consumer Price Index for all items, Urban Consumers (with a base period of January 1998).[57]

Table 1-9 Inflation adjusted total price per MWh by category: 2017 and 2018[58]

Category	2017 $/MWh	2017 ($ Millions)	2017 Percent of Total	2018 $/MWh	2018 ($ Millions)	2018 Percent of Total	Percent Change
Load Weighted Energy	$20.43	$15,500	58.2%	$24.65	$19,498	61.4%	20.7%
Capacity	$7.43	$5,636	21.2%	$8.37	$6,622	20.9%	12.7%
Capacity	$7.40	$5,618	21.1%	$8.34	$6,600	20.8%	12.7%
Capacity (FRR)	$0.00	$0	0.0%	$0.00	$0	0.0%	0.0%
Capacity (RMR)	$0.02	$18	0.1%	$0.03	$22	0.1%	14.9%
Transmission	$6.29	$4,774	17.9%	$6.10	$4,823	15.2%	(3.1%)
Transmission Service Charges	$5.82	$4,419	16.6%	$5.67	$4,483	14.1%	(2.7%)
Transmission Enhancement Cost Recovery	$0.42	$321	1.2%	$0.37	$292	0.9%	(12.7%)
Transmission Owner (Schedule 1A)	$0.06	$48	0.2%	$0.06	$48	0.2%	(5.3%)
Transmission Seams Elimination Cost Assignment (SECA)	($0.02)	($14)	(0.1%)	$0.00	$0	0.0%	
Transmission Facility Charges	$0.00	$0	0.0%	$0.00	$0	0.0%	0.0%
Ancillary	$0.51	$385	1.4%	$0.53	$421	1.3%	4.8%
Reactive	$0.28	$216	0.8%	$0.28	$220	0.7%	(2.3%)
Regulation	$0.09	$69	0.3%	$0.12	$94	0.3%	30.9%
Black Start	$0.06	$46	0.2%	$0.05	$42	0.1%	(12.7%)
Synchronized Reserves	$0.04	$28	0.1%	$0.04	$32	0.1%	12.1%
Non-Synchronized Reserves	$0.01	$5	0.0%	$0.01	$10	0.0%	101.6%
Day Ahead Scheduling Reserve (DASR)	$0.03	$23	0.1%	$0.03	$24	0.1%	(0.3%)
Administration	$0.34	$259	1.0%	$0.32	$257	0.8%	(5.1%)
PJM Administrative Fees	$0.32	$242	0.9%	$0.30	$239	0.8%	(5.1%)
NERC/RFC	$0.02	$16	0.1%	$0.02	$16	0.1%	(3.3%)
RTO Startup and Expansion	$0.00	$2	0.0%	$0.00	$2	0.0%	(9.5%)
Energy Uplift (Operating Reserves)	$0.09	$70	0.3%	$0.15	$120	0.4%	63.9%
Demand Response	$0.00	$3	0.0%	$0.00	$3	0.0%	(4.5%)
Load Response	$0.00	$3	0.0%	$0.00	$3	0.0%	(4.5%)
Emergency Load Response	$0.00	$0	0.0%	$0.00	$0	0.0%	0.0%
Emergency Energy	$0.00	$0	0.0%	$0.00	$0	0.0%	0.0%
Total Price	$35.09	$26,628	100.0%	$40.13	$31,744	100.0%	14.3%
Total Load (GWh)	758,775			791,093			4.3%
Total Billing ($ Billions)	$26.63			$31.74			19.2%

57 US Consumer Price Index for all items, Urban Consumers (base period: January 1998), published by *Bureau of Labor Statistics*. <http://download.bls.gov/pub/time.series/cu/cu.data.1.AllItems> (January 11, 2019)

58 Note: The totals in this table include after the fact billing adjustments and may not match totals presented in past reports.

Table 1-10 shows the average price, by component of the total wholesale power price per MWh, for calendar years 1999 through 2018.

Table 1-10 Total price per MWh by category: 1999 through 2018[59]

Category	1999 $/MWh	2000 $/MWh	2001 $/MWh	2002 $/MWh	2003 $/MWh	2004 $/MWh	2005 $/MWh	2006 $/MWh	2007 $/MWh	2008 $/MWh	2009 $/MWh	2010 $/MWh
Load Weighted Energy	$34.07	$30.72	$36.65	$31.60	$41.23	$44.34	$63.46	$53.35	$61.66	$71.13	$39.05	$48.35
Capacity	$0.14	$0.25	$0.27	$0.12	$0.08	$0.09	$0.04	$0.11	$3.58	$7.84	$10.79	$12.17
Capacity	$0.14	$0.25	$0.27	$0.12	$0.08	$0.09	$0.03	$0.03	$3.53	$7.80	$10.78	$12.15
Capacity (FRR)	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Capacity (RMR)	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.02	$0.08	$0.05	$0.04	$0.01	$0.02
Transmission	$3.49	$4.13	$3.56	$3.46	$3.64	$3.43	$3.30	$3.34	$3.55	$3.83	$4.22	$4.33
Transmission Service Charges	$3.41	$4.03	$3.48	$3.39	$3.57	$3.28	$2.71	$3.18	$3.45	$3.68	$4.03	$4.04
Transmission Enhancement Cost Recovery	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.01	$0.06	$0.11	$0.20
Transmission Owner (Schedule 1A)	$0.07	$0.09	$0.08	$0.07	$0.07	$0.10	$0.09	$0.09	$0.09	$0.09	$0.09	$0.09
Transmission Seams Elimination Cost Assignment (SECA)	$0.00	$0.00	$0.00	$0.00	$0.00	$0.05	$0.50	$0.07	$0.00	$0.00	$0.00	$0.00
Transmission Facility Charges	$0.01	$0.01	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Ancillary	$0.41	$0.68	$0.75	$0.63	$0.91	$0.91	$1.19	$0.92	$1.00	$1.15	$0.78	$0.90
Reactive	$0.26	$0.29	$0.22	$0.20	$0.24	$0.26	$0.26	$0.29	$0.29	$0.34	$0.36	$0.45
Regulation	$0.15	$0.39	$0.53	$0.42	$0.50	$0.51	$0.80	$0.53	$0.63	$0.70	$0.34	$0.36
Black Start	$0.00	$0.00	$0.00	$0.00	$0.02	$0.02	$0.02	$0.02	$0.02	$0.02	$0.02	$0.02
Synchronized Reserves	$0.00	$0.00	$0.00	$0.01	$0.15	$0.13	$0.11	$0.08	$0.06	$0.08	$0.05	$0.07
Non-Synchronized Reserves	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Day Ahead Scheduling Reserve (DASR)	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.01	$0.00	$0.01
Administration	$0.23	$0.26	$0.73	$0.86	$1.05	$1.00	$0.73	$0.75	$0.75	$0.41	$0.34	$0.39
PJM Administrative Fees	$0.23	$0.26	$0.71	$0.86	$1.05	$0.93	$0.72	$0.74	$0.72	$0.39	$0.31	$0.36
NERC/RFC	$0.00	($0.00)	$0.01	$0.01	$0.01	$0.01	$0.01	($0.00)	$0.01	$0.01	$0.02	$0.02
RTO Startup and Expansion	$0.00	$0.00	$0.00	$0.00	$0.00	$0.06	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01
Energy Uplift (Operating Reserves)	$0.52	$0.93	$1.27	$0.72	$0.89	$0.95	$1.07	$0.47	$0.65	$0.64	$0.48	$0.80
Demand Response	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.03	$0.06	$0.05	$0.01	$0.03
Load Response	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.03	$0.06	$0.05	$0.01	$0.01
Emergency Load Response	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.02
Emergency Energy	$0.07	$0.02	$0.00	$0.00	$0.02	$0.00	$0.02	$0.00	$0.00	$0.00	$0.00	$0.00
Total Price ($/MWh)	$38.92	$36.98	$43.22	$37.39	$47.83	$50.71	$69.81	$58.97	$71.25	$85.05	$55.66	$66.97
Total Load (GWh)	259,623	264,510	265,398	312,899	327,533	438,874	684,592	696,165	715,524	698,459	666,069	697,391
Total Billing ($ Billions)	$10.10	$9.78	$11.47	$11.70	$15.67	$22.26	$47.79	$41.05	$50.98	$59.40	$37.08	$46.70

Category	2011 $/MWh	2012 $/MWh	2013 $/MWh	2014 $/MWh	2015 $/MWh	2016 $/MWh	2017 $/MWh	2018 $/MWh
Load Weighted Energy	$45.94	$35.23	$38.66	$53.14	$36.16	$29.23	$30.99	$38.24
Capacity	$10.37	$6.66	$7.29	$9.25	$11.25	$10.96	$11.27	$13.01
Capacity	$9.71	$6.05	$7.13	$9.01	$11.12	$10.96	$11.23	$12.97
Capacity (FRR)	$0.53	$0.52	$0.11	$0.20	$0.13	$0.00	$0.00	$0.00
Capacity (RMR)	$0.13	$0.08	$0.06	$0.04	($0.00)	($0.00)	$0.04	$0.04
Transmission	$4.86	$5.32	$5.65	$6.46	$7.69	$8.42	$9.54	$9.47
Transmission Service Charges	$4.49	$4.90	$5.21	$5.96	$7.09	$7.81	$8.83	$8.81
Transmission Enhancement Cost Recovery	$0.27	$0.34	$0.36	$0.41	$0.51	$0.52	$0.64	$0.57
Transmission Owner (Schedule 1A)	$0.09	$0.08	$0.08	$0.09	$0.09	$0.09	$0.10	$0.09
Transmission Seams Elimination Cost Assignment (SECA)	($0.00)	$0.00	$0.00	$0.00	$0.00	$0.00	($0.03)	$0.00
Transmission Facility Charges	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Ancillary	$0.90	$0.84	$1.24	$0.99	$0.91	$0.71	$0.77	$0.83
Reactive	$0.41	$0.46	$0.76	$0.40	$0.37	$0.38	$0.43	$0.43
Regulation	$0.32	$0.26	$0.25	$0.33	$0.23	$0.11	$0.14	$0.18
Black Start	$0.02	$0.04	$0.14	$0.08	$0.08	$0.09	$0.09	$0.08
Synchronized Reserves	$0.09	$0.04	$0.04	$0.12	$0.11	$0.05	$0.06	$0.06
Non-Synchronized Reserves	$0.00	$0.00	$0.00	$0.02	$0.02	$0.01	$0.01	$0.02
Day Ahead Scheduling Reserve (DASR)	$0.05	$0.05	$0.06	$0.05	$0.10	$0.07	$0.05	$0.05
Administration	$0.40	$0.46	$0.45	$0.46	$0.47	$0.46	$0.52	$0.50
PJM Administrative Fees	$0.37	$0.43	$0.42	$0.43	$0.43	$0.43	$0.48	$0.47
NERC/RFC	$0.02	$0.02	$0.02	$0.03	$0.03	$0.03	$0.03	$0.03
RTO Startup and Expansion	$0.01	$0.01	$0.01	$0.01	$0.01	$0.00	$0.00	$0.00
Energy Uplift (Operating Reserves)	$0.78	$0.74	$0.55	$1.11	$0.38	$0.17	$0.14	$0.23
Demand Response	$0.03	$0.03	$0.08	$0.08	$0.02	$0.01	$0.01	$0.01
Load Response	$0.01	$0.02	$0.01	$0.03	$0.02	$0.01	$0.01	$0.01
Emergency Load Response	$0.02	$0.01	$0.06	$0.06	$0.00	$0.00	$0.00	$0.00
Emergency Energy	$0.00	$0.00	$0.00	$0.01	$0.00	$0.00	$0.00	$0.00
Total Price ($/MWh)	$63.28	$49.28	$53.93	$71.49	$56.87	$49.97	$53.24	$62.30
Total Load (GWh)	723,101	764,300	773,790	780,505	776,093	778,269	758,775	791,093
Total Billing ($ Billions)	$45.76	$37.67	$41.73	$55.80	$44.14	$38.89	$40.40	$49.29

59 Note: The totals in this table include after the fact billing adjustments and may not match totals presented in past reports.

Table 1-11 shows the inflation adjusted average price, by component of the total wholesale power price per MWh, for calendar years 1999 through 2018.[60]

Table 1-11 Inflation adjusted total price per MWh by category: 1999 through 2018[61]

Category	1999 $/MWh	2000 $/MWh	2001 $/MWh	2002 $/MWh	2003 $/MWh	2004 $/MWh	2005 $/MWh	2006 $/MWh	2007 $/MWh	2008 $/MWh	2009 $/MWh	2010 $/MWh
Load Weighted Energy	$33.04	$28.80	$33.45	$28.35	$36.24	$37.91	$52.37	$42.73	$48.06	$53.27	$29.46	$35.83
Capacity	$0.13	$0.23	$0.24	$0.11	$0.07	$0.08	$0.03	$0.08	$2.77	$5.88	$8.12	$9.02
Capacity	$0.13	$0.23	$0.24	$0.11	$0.07	$0.08	$0.02	$0.02	$2.73	$5.85	$8.11	$9.00
Capacity (FRR)	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Capacity (RMR)	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.01	$0.06	$0.04	$0.03	$0.01	$0.01
Transmission	$3.38	$3.88	$3.25	$3.10	$3.20	$2.93	$2.73	$2.68	$2.76	$2.87	$3.18	$3.21
Transmission Service Charges	$3.31	$3.79	$3.17	$3.04	$3.13	$2.80	$2.24	$2.55	$2.69	$2.76	$3.04	$2.99
Transmission Enhancement Cost Recovery	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.04	$0.08	$0.15
Transmission Owner (Schedule 1A)	$0.07	$0.08	$0.07	$0.06	$0.06	$0.08	$0.07	$0.07	$0.07	$0.07	$0.06	$0.07
Transmission Seams Elimination Cost Assignment (SECA)	$0.00	$0.00	$0.00	$0.00	$0.00	$0.04	$0.41	$0.06	$0.00	$0.00	$0.00	$0.00
Transmission Facility Charges	$0.01	$0.01	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Ancillary	$0.40	$0.64	$0.68	$0.56	$0.80	$0.77	$0.98	$0.74	$0.78	$0.86	$0.59	$0.66
Reactive	$0.25	$0.27	$0.20	$0.18	$0.21	$0.22	$0.21	$0.23	$0.23	$0.25	$0.27	$0.33
Regulation	$0.15	$0.37	$0.48	$0.38	$0.44	$0.43	$0.66	$0.42	$0.49	$0.52	$0.26	$0.27
Black Start	$0.00	$0.00	$0.00	$0.00	$0.01	$0.01	$0.02	$0.02	$0.02	$0.02	$0.02	$0.01
Synchronized Reserves	$0.00	$0.00	$0.00	$0.01	$0.13	$0.11	$0.09	$0.07	$0.05	$0.06	$0.04	$0.05
Non-Synchronized Reserves	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Day Ahead Scheduling Reserve (DASR)	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.01	$0.00	$0.01
Administration	$0.22	$0.24	$0.66	$0.77	$0.93	$0.85	$0.61	$0.60	$0.58	$0.31	$0.25	$0.29
PJM Administrative Fees	$0.22	$0.25	$0.65	$0.77	$0.92	$0.79	$0.60	$0.59	$0.56	$0.29	$0.23	$0.27
NERC/RFC	$0.00	($0.00)	$0.01	$0.01	$0.01	$0.01	$0.00	($0.00)	$0.01	$0.01	$0.01	$0.02
RTO Startup and Expansion	$0.00	$0.00	$0.00	$0.00	$0.00	$0.05	$0.00	$0.01	$0.01	$0.01	$0.01	$0.01
Energy Uplift (Operating Reserves)	$0.50	$0.87	$1.15	$0.65	$0.78	$0.81	$0.88	$0.38	$0.51	$0.48	$0.36	$0.59
Demand Response	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.02	$0.05	$0.03	$0.00	$0.02
Load Response	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.02	$0.05	$0.03	$0.00	$0.01
Emergency Load Response	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.01
Emergency Energy	$0.07	$0.02	$0.00	$0.00	$0.02	$0.00	$0.02	$0.00	$0.00	$0.00	$0.00	$0.00
Total Price ($/MWh)	$37.75	$34.68	$39.44	$33.54	$42.04	$43.36	$57.63	$47.23	$55.51	$63.71	$41.97	$49.63
Total Load (GWh)	259,623	264,510	265,398	312,899	327,533	438,874	684,592	696,165	715,524	698,459	666,069	697,391
Total Billing ($ Billions)	$9.80	$9.17	$10.47	$10.50	$13.77	$19.03	$39.45	$32.88	$39.72	$44.50	$27.95	$34.61

Category	2011 $/MWh	2012 $/MWh	2013 $/MWh	2014 $/MWh	2015 $/MWh	2016 $/MWh	2017 $/MWh	2018 $/MWh
Load Weighted Energy	$33.01	$24.80	$26.82	$36.37	$24.69	$19.68	$20.43	$24.65
Capacity	$7.46	$4.69	$5.06	$6.31	$7.66	$7.38	$7.43	$8.37
Capacity	$6.99	$4.26	$4.94	$6.15	$7.58	$7.38	$7.40	$8.34
Capacity (FRR)	$0.38	$0.37	$0.07	$0.14	$0.09	$0.00	$0.00	$0.00
Capacity (RMR)	$0.09	$0.06	$0.04	$0.03	($0.00)	($0.00)	$0.02	$0.03
Transmission	$3.49	$3.74	$3.92	$4.41	$5.24	$5.67	$6.29	$6.10
Transmission Service Charges	$3.23	$3.45	$3.61	$4.07	$4.84	$5.26	$5.82	$5.67
Transmission Enhancement Cost Recovery	$0.20	$0.24	$0.25	$0.28	$0.34	$0.35	$0.42	$0.37
Transmission Owner (Schedule 1A)	$0.06	$0.06	$0.06	$0.06	$0.06	$0.06	$0.06	$0.06
Transmission Seams Elimination Cost Assignment (SECA)	($0.00)	$0.00	$0.00	$0.00	$0.00	$0.00	($0.02)	$0.00
Transmission Facility Charges	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Ancillary	$0.64	$0.59	$0.86	$0.67	$0.62	$0.48	$0.51	$0.53
Reactive	$0.29	$0.32	$0.53	$0.27	$0.25	$0.26	$0.28	$0.28
Regulation	$0.23	$0.18	$0.17	$0.22	$0.16	$0.07	$0.09	$0.12
Black Start	$0.01	$0.03	$0.10	$0.05	$0.05	$0.06	$0.06	$0.05
Synchronized Reserves	$0.07	$0.03	$0.03	$0.08	$0.08	$0.04	$0.04	$0.04
Non-Synchronized Reserves	$0.00	$0.00	$0.00	$0.01	$0.01	$0.01	$0.01	$0.01
Day Ahead Scheduling Reserve (DASR)	$0.04	$0.03	$0.04	$0.03	$0.07	$0.05	$0.03	$0.03
Administration	$0.29	$0.33	$0.31	$0.32	$0.32	$0.31	$0.34	$0.32
PJM Administrative Fees	$0.26	$0.30	$0.29	$0.29	$0.29	$0.29	$0.32	$0.30
NERC/RFC	$0.01	$0.02	$0.02	$0.02	$0.02	$0.02	$0.02	$0.02
RTO Startup and Expansion	$0.01	$0.01	$0.01	$0.01	$0.00	$0.00	$0.00	$0.00
Energy Uplift (Operating Reserves)	$0.56	$0.52	$0.38	$0.77	$0.26	$0.12	$0.09	$0.15
Demand Response	$0.02	$0.02	$0.05	$0.05	$0.01	$0.01	$0.00	$0.00
Load Response	$0.01	$0.01	$0.01	$0.02	$0.01	$0.01	$0.00	$0.00
Emergency Load Response	$0.01	$0.01	$0.04	$0.04	$0.00	$0.00	$0.00	$0.00
Emergency Energy	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Total Price ($/MWh)	$45.48	$34.69	$37.41	$48.90	$38.81	$33.64	$35.09	$40.13
Total Load (GWh)	723,101	764,300	773,790	780,505	776,093	778,269	758,775	791,093
Total Billing ($ Billions)	$32.88	$26.52	$28.95	$38.17	$30.12	$26.18	$26.63	$31.74

60 US Consumer Price Index for all items, Urban Consumers (base period: January 1998), published by *Bureau of Labor Statistics*. <http://download.bls.gov/pub/time.series/cu/cu.data.1.AllItems> (January 11, 2019).

61 Note: The totals in this table include after the fact billing adjustments and may not match totals presented in past reports.

Table 1-12 shows the percent of average price, by component of the wholesale power price per MWh, for calendar years 1999 through 2018.

Table 1-12 Percent of total price per MWh by category: 1999 through 2018[62]

Category	Percent of Total Charges 1999	Percent of Total Charges 2000	Percent of Total Charges 2001	Percent of Total Charges 2002	Percent of Total Charges 2003	Percent of Total Charges 2004	Percent of Total Charges 2005	Percent of Total Charges 2006	Percent of Total Charges 2007	Percent of Total Charges 2008	Percent of Total Charges 2009	Percent of Total Charges 2010
Load Weighted Energy	87.5%	83.1%	84.8%	84.5%	86.2%	87.4%	90.9%	90.5%	86.5%	83.6%	70.1%	72.2%
Capacity	0.4%	0.7%	0.6%	0.3%	0.2%	0.2%	0.1%	0.2%	5.0%	9.2%	19.4%	18.2%
Capacity	0.4%	0.7%	0.6%	0.3%	0.2%	0.2%	0.0%	0.0%	4.9%	9.2%	19.4%	18.1%
Capacity (FRR)	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Capacity (RMR)	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.1%	0.1%	0.0%	0.0%	0.0%
Transmission	9.0%	11.2%	8.2%	9.3%	7.6%	6.8%	4.7%	5.7%	5.0%	4.5%	7.6%	6.5%
Transmission Service Charges	8.8%	10.9%	8.0%	9.1%	7.5%	6.5%	3.9%	5.4%	4.8%	4.3%	7.2%	6.0%
Transmission Enhancement Cost Recovery	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.1%	0.2%	0.3%
Transmission Owner (Schedule 1A)	0.2%	0.2%	0.2%	0.2%	0.1%	0.2%	0.1%	0.1%	0.1%	0.1%	0.2%	0.1%
Transmission Seams Elimination Cost Assignment (SECA)	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Transmission Facility Charges	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Ancillary	1.1%	1.8%	1.7%	1.7%	1.9%	1.8%	1.7%	1.6%	1.4%	1.4%	1.4%	1.3%
Reactive	0.7%	0.8%	0.5%	0.5%	0.5%	0.5%	0.4%	0.5%	0.4%	0.4%	0.7%	0.7%
Regulation	0.4%	1.1%	1.2%	1.1%	1.1%	1.0%	1.1%	0.9%	0.9%	0.8%	0.6%	0.5%
Black Start	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Synchronized Reserves	0.0%	0.0%	0.0%	0.0%	0.3%	0.3%	0.2%	0.1%	0.1%	0.1%	0.1%	0.1%
Non-Synchronized Reserves	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Day Ahead Scheduling Reserve (DASR)	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Administration	0.6%	0.7%	1.7%	2.3%	2.2%	2.0%	1.1%	1.3%	1.0%	0.5%	0.6%	0.6%
PJM Administrative Fees	0.6%	0.7%	1.7%	2.3%	2.2%	1.8%	1.0%	1.3%	1.0%	0.5%	0.6%	0.5%
NERC/RFC	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
RTO Startup and Expansion	0.0%	0.0%	0.0%	0.0%	0.0%	0.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Energy Uplift (Operating Reserves)	1.3%	2.5%	2.9%	1.9%	1.9%	1.9%	1.5%	0.8%	0.9%	0.8%	0.9%	1.2%
Demand Response	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.1%	0.1%	0.0%	0.0%
Load Response	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.1%	0.1%	0.0%	0.0%
Emergency Load Response	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Emergency Energy	0.2%	0.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Total Price	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%

Category	Percent of Total Charges 2011	Percent of Total Charges 2012	Percent of Total Charges 2013	Percent of Total Charges 2014	Percent of Total Charges 2015	Percent of Total Charges 2016	Percent of Total Charges 2017	Percent of Total Charges 2018
Load Weighted Energy	72.6%	71.5%	71.7%	74.3%	63.6%	58.5%	58.2%	61.4%
Capacity	16.4%	13.5%	13.5%	12.9%	19.8%	21.9%	21.2%	20.9%
Capacity	15.4%	12.3%	13.2%	12.6%	19.6%	21.9%	21.1%	20.8%
Capacity (FRR)	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Capacity (RMR)	0.2%	0.2%	0.1%	0.1%	0.0%	0.0%	0.1%	0.1%
Transmission	7.7%	10.8%	10.5%	9.0%	13.5%	16.9%	17.9%	15.2%
Transmission Service Charges	7.1%	9.9%	9.7%	8.3%	12.5%	15.6%	16.6%	14.1%
Transmission Enhancement Cost Recovery	0.4%	0.7%	0.7%	0.6%	0.9%	1.0%	1.2%	0.9%
Transmission Owner (Schedule 1A)	0.1%	0.2%	0.2%	0.1%	0.2%	0.2%	0.2%	0.2%
Transmission Seams Elimination Cost Assignment (SECA)	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Transmission Facility Charges	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Ancillary	1.4%	1.7%	2.3%	1.4%	1.6%	1.4%	1.4%	1.3%
Reactive	0.6%	0.9%	1.4%	0.6%	0.7%	0.8%	0.8%	0.7%
Regulation	0.5%	0.5%	0.5%	0.5%	0.4%	0.2%	0.3%	0.3%
Black Start	0.0%	0.1%	0.3%	0.1%	0.1%	0.2%	0.2%	0.1%
Synchronized Reserves	0.1%	0.1%	0.1%	0.2%	0.2%	0.1%	0.1%	0.1%
Non-Synchronized Reserves	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Day Ahead Scheduling Reserve (DASR)	0.1%	0.1%	0.1%	0.1%	0.2%	0.1%	0.1%	0.1%
Administration	0.6%	0.9%	0.8%	0.6%	0.8%	0.9%	1.0%	0.8%
PJM Administrative Fees	0.6%	0.9%	0.8%	0.6%	0.8%	0.9%	0.9%	0.8%
NERC/RFC	0.0%	0.0%	0.0%	0.0%	0.1%	0.1%	0.1%	0.1%
RTO Startup and Expansion	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Energy Uplift (Operating Reserves)	1.2%	1.5%	1.0%	1.6%	0.7%	0.3%	0.3%	0.4%
Demand Response	0.0%	0.1%	0.1%	0.1%	0.0%	0.0%	0.0%	0.0%
Load Response	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Emergency Load Response	0.0%	0.0%	0.1%	0.1%	0.0%	0.0%	0.0%	0.0%
Emergency Energy	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Total Price	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%

62 Note: The totals in this table include after the fact billing adjustments and may not match totals presented in past reports.

Figure 1-3 shows the contributions of load-weighted energy, capacity and transmission service charges to the total price of wholesale power for each quarter since 1999.

Figure 1-3 Top three components of quarterly total price ($/MWh): 1999 through 2018[63]

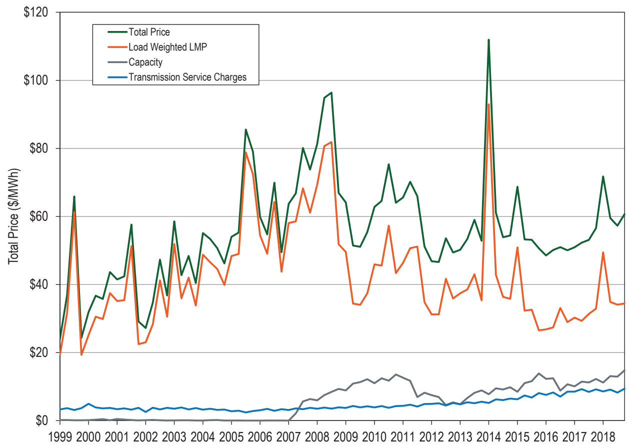


Figure 1-4 shows the inflation adjusted contributions of load-weighted energy, capacity and transmission service charges to the total price of wholesale power for each quarter since 1999.[64]

Figure 1-4 Inflation adjusted top three components of quarterly total price ($/MWh): 1999 through 2018[65]

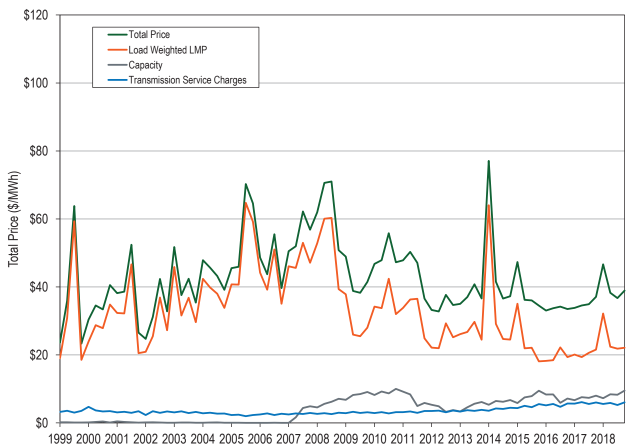
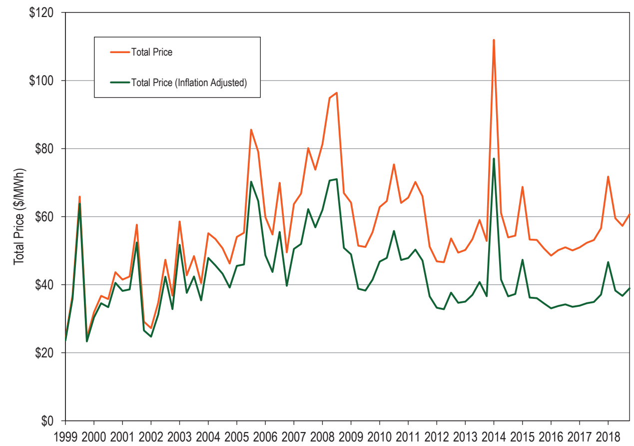


Figure 1-5 shows the total price of wholesale power and the inflation adjusted total price of wholesale power for each quarter since 1999.[66]

Figure 1-5 Quarterly total price and quarterly inflation adjusted total price ($/MWh): 1999 through 2018[67 68]



Section Overviews

Overview: Section 3, Energy Market

Market Structure

- **Supply.** Supply includes physical generation, imports and virtual transactions. The maximum average on peak hourly offered real-time supply was 138,142 MWh for the winter and 150,674 MWh for the summer. In 2018, 12,826.2 MW of new resources were added and 5,522.7 MW were retired.

  PJM average real-time cleared generation in 2018 increased by 3.6 percent 2017, from 90,945 MWh to 94,236 MWh.

  PJM average day-ahead cleared supply in 2018, including INCs and up to congestion transactions, decreased by 12.3 percent from 2017, from 130,601 MWh to 114,556 MWh.

- **Aggregate Pivotal Suppliers.** The PJM energy market at times requires generation from pivotal suppliers to meet load, resulting in aggregate market power

63 Note: The totals presented in this figure include after the fact billing adjustments and may not match totals presented in past reports.

64 US Consumer Price Index for all items, Urban Consumers (base period: January 1998), published by *Bureau of Labor Statistics*. <http://download.bls.gov/pub/time.series/cu/cu.data.1.AllItems> (January 11, 2019).

65 Note: The totals presented in this figure include after the fact billing adjustments and may not match totals presented in past reports.

66 US Consumer Price Index for all items, Urban Consumers (base period: January 1998), published by *Bureau of Labor Statistics*. <http://download.bls.gov/pub/time.series/cu/cu.data.1.AllItems> (January 11, 2019).

67 Note: The totals presented in this figure include after the fact billing adjustments and may not match totals presented in past reports.

68 US Consumer Price Index for all items, Urban Consumers (base period: January 1998), published by *Bureau of Labor Statistics*. <http://download.bls.gov/pub/time.series/cu/cu.data.1.AllItems> (January 11, 2019).

even when the HHI level indicates that the aggregate market is unconcentrated.

- **Generation Fuel Mix.** In 2018, coal units provided 28.6 percent, nuclear units 34.2 percent and natural gas units 30.6 percent of total generation. Compared to 2017, generation from coal units decreased 6.6 percent, generation from natural gas units increased 18.4 percent and generation from nuclear units decreased 0.5 percent.

- **Fuel Diversity.** In 2018, the fuel diversity of energy generation, measured by the fuel diversity index for energy (FDI_e), increased 0.9 percent over the FDI_e for 2017.

- **Marginal Resources.** In the PJM Real-Time Energy Market, in 2018, coal units were 27.3 percent and natural gas units were 63.3 percent of marginal resources. In 2017, coal units were 32.3 percent and natural gas units were 53.3 percent of marginal resources. Among the natural gas units that were marginal in 2018, nearly 85 percent were combined cycle units.

  In the PJM Day-Ahead Energy Market, in 2018, up to congestion transactions were 62.3 percent, INCs were 9.8 percent, DECs were 16.9 percent, and generation resources were 10.9 percent of marginal resources. In 2017, up to congestion transactions were 79.9 percent, INCs were 5.5 percent, DECs were 10.2 percent, and generation resources were 4.3 percent of marginal resources.

- **Demand.** Demand includes physical load and exports and virtual transactions. The PJM accounting peak load in 2018 was 147,042 MWh in the HE 1700 on August 28, 2018, which was 4,656 MWh, 3.3 percent, higher than the PJM peak load for 2017, which was 142,387 MWh in the HE 1800 on July 19, 2017.

  PJM average real-time demand in 2018 increased by 4.3 percent from 2017, from 86,618 MWh to 90,307 MWh. PJM average day-ahead demand in 2018, including DECs and up to congestion transactions, decreased by 12.5 percent from 2017, from 125,792 MWh to 110,091 MWh.

- **Supply and Demand: Load and Spot Market.** Companies that serve load in PJM do so using a combination of self-supply, bilateral market purchases and spot market purchases. For 2018, 13.5 percent of real-time load was supplied by bilateral contracts, 28.8 percent by spot market purchases and 58.8 percent by self-supply. Compared to 2017, reliance on bilateral contracts decreased by 0.9 percentage points, reliance on spot market purchases increased by 1.3 percentage points and reliance on self-supply decreased by 0.1 percentage points.

Market Behavior

- **Offer Capping for Local Market Power.** PJM offer caps units when the local market structure is noncompetitive. Offer capping is an effective means of addressing local market power when the rules are designed and implemented properly. Offer capping levels have historically been low in PJM. In the Day-Ahead Energy Market, for units committed to provide energy for local constraint relief, offer-capped unit hours increased from 0.0 percent in 2017 to 0.1 percent in 2018. In the Real-Time Energy Market, for units committed to provide energy for local constraint relief, offer-capped unit hours increased from 0.3 percent in 2017 to 0.9 percent in 2018. While overall offer capping levels have been low, there are a significant number of units with persistent structural local market power that would have a significant impact on prices in the absence of local market power mitigation.

  In 2018, 14 control zones experienced congestion resulting from one or more constraints binding for 100 or more hours. The analysis of the application of the TPS test to local markets demonstrates that it is working successfully to identify pivotal owners when the market structure is noncompetitive and to ensure that owners are not subject to offer capping when the market structure is competitive. There are, however, identified issues with the application of market power mitigation to resources whose owners fail the TPS test that can result in the exercise of local market power. These issues need to be addressed.

- **Offer Capping for Reliability.** PJM also offer caps units that are committed for reliability reasons, including for reactive support. In the Day-Ahead Energy Market, for units committed for reliability reasons, offer-capped unit hours remained at 0.1 percent in 2017 and 2018. In the Real-Time Energy

Market, for units committed for reliability reasons, offer-capped unit hours remained at 0.1 percent in 2017 and 2018.

- **Markup Index.** The markup index is a summary measure of participant offer behavior for individual marginal units. In 2018, in the PJM Real-Time Energy Market, 88.1 percent of marginal units had offer prices less than $50 per MWh. The average dollar markup of units with offer prices less than $25 was negative (-$0.44 per MWh) when using unadjusted cost-based offers. The average dollar markup of units with offer prices between $25 and $50 was positive ($1.91 per MWh) when using unadjusted cost-based offers. Negative markup means the unit is offering to run at a price less than its cost-based offer, demonstrating a revealed short run marginal cost that is less than the allowable cost-based offer under the PJM market rules. Some marginal units did have substantial markups. Using the unadjusted cost-based offers, the highest markup for any marginal unit in 2018 was more than $500 per MWh while the highest markup in 2017 was more than $700 per MWh. During the period of cold weather and high demand in January, several units in the PJM market were offered with high markups.

  In 2018, in the PJM Day-Ahead Energy Market, 95.5 percent of marginal generating units had offer prices less than $50 per MWh. The average dollar markup of units with offer prices less than $25 was positive ($0.27 per MWh) when using unadjusted cost-based offers. The average dollar markup of units with offer prices between $25 and $50 was positive ($3.21 per MWh) when using unadjusted cost-based offers. Using the unadjusted cost-based offers, the highest markup for any marginal unit in 2018 was $200 per MWh, while the highest markup in 2017 was $85 per MWh.

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

  The markup behavior shown in the markup frequency distributions also shows that a substantial number of units were offered with high markups, consistent with the exercise of market power. Markup for gas fired units increased in 2018.

- **Frequently Mitigated Units (FMU) and Associated Units (AU).** A new FMU rule became effective November 1, 2014, limiting the availability of FMU adders to units with net revenues less than unit going forward costs. The number of units that were eligible for an FMU or AU adder declined from an average of 70 units during the first 11 months of 2014, to zero since December 2014.

- **Virtual Offers and Bids.** Any market participant in the PJM Day-Ahead Energy Market can use increment offers, decrement bids, up to congestion transactions, import transactions and export transactions as financial instruments that do not require physical generation or load. In 2018, the average hourly increment offers submitted and cleared MW decreased by 27.5 percent and 41.3 percent, from 7,968 MW and 4,562 MW in 2017 to 5,776 MW and 2,676 MW in 2018. The average hourly decrement bids submitted and cleared MW decreased by 14.2 percent and 28.0 percent, from 7,874 MW and 4,035 MW in 2017 to 6,753 MW and 2,906 MW in 2018. The average hourly up to congestion submitted and cleared MW decreased by 57.3 percent and 48.7 percent, from 137,419 MW and 34,387 MW in 2017 to 58,650 MW and 17,624 MW in 2018.

- **Generator Offers.** Generator offers are categorized as dispatchable and self scheduled. Units which are available for economic dispatch are dispatchable. Units which are self scheduled to generate fixed output are categorized as self scheduled. Units which are self scheduled at their economic minimum and are available for economic dispatch up to their economic maximum are categorized as self scheduled and dispatchable. Of all generator offers by MW in 2018, 25.4 percent were offered as available for economic dispatch, 31.3 percent were offered at their economic minimum, 4.5 percent were offered as emergency dispatch, 16.2 percent were offered as self scheduled, and 21.5 percent were offered as self scheduled and dispatchable.

Market Performance

- **Prices.** PJM LMPs are a direct measure of market performance. Price level is a good, general indicator of market performance, although the number of factors influencing the overall level of prices means it must be analyzed carefully. Among other things, overall average prices reflect changes in supply and demand, generation fuel mix, the cost of fuel, emissions related expenses, markup and local price differences caused by congestion. PJM also may administratively set prices with the creation of closed loop interfaces related to demand side resources or reactive power, the application of transmission penalty factors, or the application of price setting logic.

  PJM real-time energy market prices increased in 2018 compared to 2017. The load-weighted, average real-time LMP was 23.4 percent higher in 2018 than in 2017, $38.24 per MWh versus $30.99 per MWh.

  PJM day-ahead energy market prices increased in 2018 compared to 2017. The load-weighted, average day-ahead LMP was 23.1 percent higher in 2018 than in 2017, $37.97 per MWh versus $30.85 per MWh.

- **Components of LMP.** In the PJM Real-Time Energy Market, in 2018, 19.4 percent of the load-weighted LMP was the result of coal costs, 42.4 percent was the result of gas costs and 0.66 percent was the result of the cost of emission allowances.

  In the PJM Day-Ahead Energy Market, in 2018, 28.4 percent of the load-weighted LMP was the result of DEC bids, 19.6 percent was the result of gas costs, 18.5 percent was the result of INC offers, 16.2 percent was the result of coal costs, and 2.6 percent was the result of up to congestion transaction offers.

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

  In the PJM Real-Time Energy Market in 2018, the unadjusted markup component of LMP was $4.56 per MWh or 11.9 percent of the PJM load-weighted, average LMP. January had the highest unadjusted off peak markup component, $11.65 per MWh, or 13.28 percent of the real-time, off peak hour load-weighted, average LMP. There were 51 hours in 2018 where the positive markup contribution to the PJM system wide, load-weighted, average LMP exceeded $80.00 per MWh. During the period of cold weather and high demand in January, some units in the PJM market were offered with high markups.

  In the PJM Day-Ahead Energy Market, INCs, DECs and UTCs have zero markups. In 2018, the unadjusted markup component of LMP resulting from generation resources was $1.22 per MWh or 3.2 percent of the PJM day-ahead load-weighted average LMP. January had the highest unadjusted peak markup component, $4.21 per MWh.

  Participant behavior was evaluated as competitive because the analysis of markup shows that marginal units generally make offers at, or close to, their marginal costs in both the Day-Ahead and Real-Time Energy Markets, although the behavior of some participants represents economic withholding.

- **Price Convergence.** Hourly and daily price differences between the Day-Ahead and Real-Time Energy Markets fluctuate continuously and substantially from positive to negative. The difference between the average day-ahead and real-time prices was -$0.06 per MWh in 2017 and $0.06 per MWh in 2018. The difference between average day-ahead and real-time prices, by itself, is not a measure of the competitiveness or effectiveness of the Day-Ahead Energy Market.

Scarcity

- There were three intervals with five minute shortage pricing on two days in 2018. On August 31, 2018, for two intervals at 0935 EPT and 0940 EPT, synchronized reserves for the RTO Zone and MAD Subzone were less than the extended synchronized reserve requirements. On September 30, 2018, for one interval at 1135 EPT, synchronized reserves for the RTO Zone and MAD Subzone were less than the extended synchronized reserve requirements.

- There were 3,776 five minute intervals, or 3.6 percent of all five minute intervals in 2018 for which at least one solved SCED case showed a shortage of reserves, and 1,865 five minute intervals, or 1.8 percent of all five minute intervals in 2018 for which more than one solved SCED case showed a shortage of reserves. PJM operators used only three RT SCED cases that showed a shortage of reserves in LPC to calculate real-time LMPs and ancillary service prices.

- On May 29, 2018, there were six Performance Assessment Intervals (PAIs) triggered in the Edison area of the AEP Zone due to a localized load shed event. On July 18, 2018, there were 18 PAIs triggered in the Lonesome Pine area on the border of Virginia and West Virginia in the AEP Zone due to a localized load shed event to control for voltage violations. These PAIs did not trigger shortage pricing since reserve requirements in PJM are only set at the RTO Zone and MAD Subzone levels, and not at locational levels smaller than the MAD Subzone.

Section 3 Recommendations

Market Power

- The MMU recommends that the market rules 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. (Priority: Medium. First reported 2009. Status: Not adopted.)
- The MMU recommends that PJM require that all fuel cost policies be algorithmic, verifiable, and systematic, and accurately reflect short run marginal costs. (Priority: Medium. First reported 2016. Status: Not adopted.)
- The MMU recommends that the 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 as the basis for Fuel Cost Policies but should not be required. (Priority: Low. First reported Q1, 2018. Status: Not adopted.)
- 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. (Priority: Low. First reported Q1, 2018. Status: Not adopted.)
- 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. (Priority: Medium. First reported 2016. Status: Not adopted.)
- The MMU recommends removal of all use of FERC System of Accounts in the Cost Development Guidelines. (Priority: Medium. First reported 2016. Status: Not adopted.)
- The MMU recommends the removal of all use of cyclic starting and peaking factors from the Cost Development Guidelines. (Priority: Medium. First reported 2016. Status: Not adopted.)
- The MMU recommends the removal of all labor costs from the Cost Development Guidelines. (Priority: Medium. First reported 2016. Status: Not adopted.)
- 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. (Priority: Medium. First reported 2016. Status: Not adopted.)
- The MMU recommends the removal of nuclear fuel and nonfuel operations and maintenance costs that are not short run marginal costs from the Cost Development Guidelines. (Priority: Medium. First reported 2016. Status: Not adopted.)
- The MMU recommends revising the pumped hydro fuel cost calculation to include day-ahead and real-time power purchases. (Priority: Low. First reported 2016. Status: Not adopted.)
- 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. (Priority: Medium. First reported 2016. Status: Adopted, 2018.)
- The MMU recommends removing the catastrophic designation for force majeure fuel supply limitations in Schedule 2. (Priority: Medium. First reported 2016. Status: Not adopted.)
- The MMU recommends that the rules governing the application of the TPS test be clarified and documented. The TPS test application in the Day-

Ahead Energy Market is not documented. (Priority: High. First reported 2015. Status: Partially adopted.)

- The MMU recommends that PJM require every market participant to make available at least one cost schedule based on the same hourly fuel type(s) and parameters at least as flexible as their offered price schedule. (Priority: Medium. First reported 2015. Status: Not adopted.)
- The MMU recommends, in order to ensure effective market power mitigation when the TPS test is failed, that markup be constant across the full MWh range of price and cost-based offers. (Priority: High. First reported 2015. Status: Not adopted.)
- 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. (Priority: High. First reported 2015. Status: Not adopted.)
- The MMU recommends that PJM retain the $1,000 per MWh offer cap in the PJM energy market except when cost-based offers exceed $1,000 per MWh, and retain other existing rules that limit incentives to exercise market power. (Priority: High. First reported 1999. Status: Partially adopted, 1999, 2017.)
- The MMU recommends the elimination of FMU and AU adders. FMU and AU adders no longer serve the purpose for which they were created and interfere with the efficient operation of PJM markets. (Priority: Medium. First reported 2012. Status: Partially adopted, 2014.)
- 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.[69] (Priority: Medium. First reported 2012. Status: Not adopted.)

69 This recommendation was accepted by PJM and filed with FERC in 2014 as part of the capacity performance updates to the RPM. See Schedule 1, Section 1.10.1A(d), Revisions to the PJM Open Access Transmission Tariff and PJM Operating Agreement (Marked/Redline Format), EL15-29-000 (December 12, 2014). FERC rejected the proposed change. See 151 FERC ¶ 61,208 at P 476 (2015).

Capacity Performance Resources

- 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. (Priority: Medium. First reported 2015. Status: Not adopted.)
- The MMU recommends that the parameters which determine nonperformance charges and the amounts of uplift payments should reflect the flexibility goals of the capacity 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. (Priority: Medium. First reported 2015. Status: Partially adopted.)
- The MMU recommends that PJM not allow nuclear generators which do not respond to prices or which only respond to manual instructions from the dispatcher to set the LMPs in the real-time market. (Priority: Low. First reported 2016. Status: Not adopted.)
- The MMU recommends that PJM document how LMPs are calculated when demand response is marginal. (Priority: Low. First reported 2014. Status: Not Adopted.)
- The MMU recommends that PJM not 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. (Priority: Medium. First reported Q3, 2018. Status: Not adopted.)
- The MMU recommends that PJM clearly define the business rules that apply to the unit specific parameter adjustment process, including PJM's implementation of the tariff rules in the PJM manuals to ensure market sellers know the requirements for their resources. (Priority: Low. First reported Q3, 2018. Status: Not adopted.)
- The MMU recommends that PJM update the tariff to clarify that all generation resources are subject

to unit specific parameter limits on their cost-based offers using the same standard and process as capacity performance capacity resources. (Priority: Medium. New recommendation. Status: Not adopted.)

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

Accurate System Modeling

- The MMU recommends that PJM explicitly state its policy on the use of transmission penalty factors including: the level of the penalty factors; the triggers for the use of the penalty factors; the appropriate line ratings to trigger the use of penalty factors; the allowed duration of the violation; the use of constraint relaxation logic; and when the transmission penalty factors will be used to set the shadow price. (Priority: Medium. First reported 2015. Status: Partially adopted.)
- The MMU recommends that PJM routinely review all transmission facility ratings and any changes to those ratings to ensure that the normal, emergency and load dump ratings used in modeling the transmission system are accurate and reflect standard ratings practice. (Priority: Low. First reported 2013. Status: Partially adopted.)
- The MMU recommends that PJM update the outage impact studies, the reliability analyses used in RPM for capacity deliverability, and the reliability analyses used in RTEP for transmission upgrades to be consistent with the more conservative emergency operations (post contingency load dump limit exceedance analysis) in the energy market that were implemented in June 2013. (Priority: Low. First reported 2013. Status: Not adopted.)
- The MMU recommends that PJM include in the tariff or appropriate manual an explanation of the initial creation of hubs, the process for modifying hub definitions and a description of how hub definitions have changed.[70] [71] (Priority: Low. First reported 2013. Status: Not adopted.)
- The MMU recommends that all buses with a net withdrawal be treated as load for purposes of calculating load and load-weighted LMP. 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. (Priority: Low. First reported 2013. Status: Not adopted.)
- The MMU recommends that PJM identify and collect data on available behind the meter generation resources, including nodal location information and relevant operating parameters. (Priority: Low. First reported 2013. Status: Partially adopted.)
- The MMU recommends that PJM increase the interaction of outage and operational restrictions data submitted by Market Participants via eDART/eGADs and offer data submitted via Markets Gateway. (Priority: Low. First reported 2017. Status: Not adopted.)

Transparency

- 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. (Priority: Medium. First reported 2015. Status: Partially adopted.)
- The MMU recommends that PJM continue to enhance its posting of market data to promote market efficiency. (Priority: Medium. First reported 2005. Status: Partially adopted.)
- 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

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

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

implement a rule based approach. (Priority: High. New recommendation. Status: Not adopted.)

Section 3 Conclusion

The MMU analyzed key elements of PJM energy market structure, participant conduct and market performance in 2018, including aggregate supply and demand, concentration ratios, aggregate pivotal supplier results, local three pivotal supplier test results, offer capping, participation in demand response programs, loads and prices.

PJM average real-time cleared generation increased by 3,292 MWh, 3.6 percent, and peak load increased by 4,656 MWh, 3.3 percent, in 2018 compared to 2017. The relationship between supply and demand, regardless of the specific market, balanced by market concentration and the extent of pivotal suppliers, is referred to as the supply-demand fundamentals or economic fundamentals. The market structure of the PJM aggregate energy market is partially competitive because aggregate market power does exist for a significant number of hours. The HHI is not a definitive measure of structural market power. The number of pivotal suppliers in the energy market is a more precise measure of structural market power than the HHI. It is possible to have pivotal suppliers in the aggregate market even when the HHI level is not in the highly concentrated range. The current market power mitigation rules for the PJM energy market rely on the assumption that the ownership structure of the aggregate market ensures competitive outcomes. This assumption requires that the total demand for energy can be met without the supply from any individual supplier or without the supply from a small group of suppliers. This assumption is not correct. There are pivotal suppliers in the aggregate energy market at times. High markups for some units demonstrate the potential to exercise market power both routinely and during high demand conditions. The existing market power mitigation measures do not address aggregate market power. The MMU is developing an aggregate market power test and will propose market power mitigation rules to address aggregate market power.

The three pivotal supplier test is applied by PJM on an ongoing basis for local energy markets in order to determine whether offer capping is required for transmission constraints.[72] However, there are some issues with the application of market power mitigation in the Day-Ahead Energy Market and the Real-Time Energy Market when market sellers fail the TPS test. These issues can be resolved by simple rule changes.

The enforcement of market power mitigation rules is undermined if the definition of a competitive offer is not correct. A competitive offer is equal to short run marginal costs. The significance of competition metrics like markup is also undermined if the definition of a competitive offer is not correct. The definition of a competitive offer, as interpreted by PJM, is not currently correct. Some unit owners include costs that are not short run marginal costs in offers, including maintenance costs. This issue can be resolved by simple rule changes to incorporate a clear and accurate definition of short run marginal costs.

Prices are a key outcome of markets. Prices vary across hours, days and years for multiple reasons. Price is an indicator of the level of competition in a market although individual prices are not always easy to interpret. In a competitive market, prices are directly related to the marginal cost to serve load in each market interval. The pattern of prices within days and across months and years illustrates how prices are directly related to supply and demand conditions and thus also illustrates the potential significance of the impact of the price elasticity of demand on prices. Energy market results in 2018 generally reflected supply-demand fundamentals, although the behavior of some participants both routinely and during high demand periods represents economic withholding. Economic withholding is the ability to increase markups substantially in tight market conditions. There are additional issues in the energy market including the uncertainties about the pricing and availability of natural gas, the way that generation owners incorporate natural gas costs in offers, and the lack of adequate incentives for unit owners to take all necessary actions to acquire fuel and operate rather than economically withhold or physically withhold.

Prices in PJM are not too low. There is no evidence to support the need for a significant change to the calculation of LMP. The underlying problem that fast start pricing and PJM's reserve pricing approach are attempting to

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

address is actually scarcity pricing, including the impact of operator actions on the definition of scarcity. Prices do not reflect market conditions when the market is tight. Rather than undercutting the basic LMP logic that is core to market efficiency, it would make more sense to directly address scarcity pricing, operator actions and the design of reserve markets. Targeted increases to the demand for reserves when the market is tight would address price formation in the energy market.

When the real-time security constrained economic dispatch (RT SCED) solution does indicate a shortage of reserves, it should be used in calculating real-time prices. There are significant issues with operator discretion and reluctance to approve RT SCED cases indicating shortage of reserves, and in using these cases to calculate prices. While it is appropriate for operators to ensure that cases that use erroneous inputs are not approved and not allowed to set prices, it is essential that operator discretion not extend beyond what is necessary and that operator discretion not prevent shortage pricing when there are shortage conditions. There are also issues with the alignment of SCED cases used for resource dispatch and the SCED cases used to calculate real-time prices. PJM should fix its current operating practices and ensure transparency regarding approval of SCED cases for resource dispatch and pricing so that market participants can have confidence in the market design to produce accurate and efficient price signals. These issues are even more critical now that PJM settles real-time energy transactions on a five minute basis.

The objective of efficient short run price signals is to minimize system production costs, not to minimize uplift. Repricing the market to reflect commitment costs would create a tradeoff between minimizing production costs and reduction of uplift. The tradeoff would exist because when commitment costs are included in prices, the price signal no longer equals the short run marginal cost and therefore no longer provides the correct signal for efficient behavior for market participants making decisions on the margin, whether resources, load, interchange transactions, or virtual traders. This tradeoff would be created by PJM's fast start pricing proposal and in a much more extensive form by PJM's convex hull pricing proposal and reserve pricing proposal.

The fast start pricing and convex hull solutions would undercut LMP logic rather than directly addressing the underlying issues. The solution is not to accept that the inflexible CT should be paid or set price-based on its commitment costs rather than its short run marginal costs. The question of why units make inflexible offers should be addressed directly. Are units inflexible because they are old and inefficient, because owners have not invested in increased flexibility or because they serve as a mechanism for the exercise of market power? The question of why this unit was built, whether it was built under cost of service regulation and whether it is efficient to retain the unit should be answered directly. The question of how to provide market incentives for investment in flexible units and for investment in increased flexibility of existing units should be addressed directly. The question of whether inflexible units should be paid uplift at all should be addressed directly. Marginal cost pricing without paying excess uplift to inflexible units would create incentives for market participants to provide flexible solutions including replacing inefficient units with flexible, efficient units.

With or without a capacity market, energy market design must permit scarcity pricing when such pricing is consistent with market conditions and constrained by reasonable rules to ensure that market power is not exercised. Scarcity pricing can serve two functions in wholesale power markets: revenue adequacy and price signals. Scarcity pricing for revenue adequacy is not required in PJM. Scarcity pricing for price signals that reflect market conditions during periods of scarcity is required in PJM. Scarcity pricing is also part of an appropriate incentive structure facing both load and generation owners in a working wholesale electric power market design. Scarcity pricing must be designed to ensure that market prices reflect actual market conditions, that scarcity pricing occurs with transparent triggers based on measured reserve levels and transparent prices, that scarcity pricing only occurs when scarcity exists, and that there are strong incentives for competitive behavior and strong disincentives to exercise market power. Such administrative scarcity pricing is a key link between energy and capacity markets.

The PJM Capacity Market is explicitly designed to provide revenue adequacy and the resultant reliability. However, the explicit balancing mechanism that included net revenues directly in unit offers in the prior capacity market design is not present in the Capacity

Performance design. The nature of a direct and explicit energy pricing net revenue true up mechanism in the capacity market should be addressed if energy revenues are expected to increase as a result of scarcity events, as a result of increased demand for reserves, or as a result of PJM's inappropriate proposals related to fast start pricing and the inclusion of maintenance expenses as short run marginal costs. The true up mechanism must address both cleared auctions and subsequent auctions. There are also significant issues with PJM's scarcity pricing rules, including the absence of a clear trigger based on measured reserve levels (the current triggers are based on estimated reserves) and the lack of adequate locational scarcity pricing options.

The overall energy market results support the conclusion that energy prices in PJM are set, generally, by marginal units operating at, or close to, their marginal costs, although this was not always the case in 2018 or prior years. This is evidence of generally competitive behavior and competitive market outcomes, although the behavior of some participants represents economic withholding. Markups were higher in 2018, especially during the cold weather in January. Given the structure of the energy market which can permit the exercise of aggregate market power, the change in some participants' behavior is a source of concern in the energy market and provides a reason to use correctly defined short run marginal cost as the sole basis for cost-based offers and a reason for implementing an aggregate market power test. The MMU concludes that the PJM energy market results were competitive in 2018.

Overview: Section 4, Energy Uplift

Energy Uplift Credits

- **Types of credits.** In 2018, energy uplift credits were $199.0 million, including $34.0 million in day-ahead generator credits, $90.2 million in balancing generator credits, $52.3 million in lost opportunity cost credits, $13.2 million in reactive credits, and $8.6 million in local constraint control credits.
- **Types of units.** Coal units received 61.3 percent of all day-ahead generator credits and 88.0 percent of all reactive service credits. Combustion turbines received 76.4 percent of all balancing generator credits and 71.9 percent of lost opportunity cost credits.
- **Economic and Noneconomic Generation.** In 2018, 84.6 percent of the day-ahead generation eligible for operating reserve credits was economic and 68.9 percent of the real-time generation eligible for operating reserve credits was economic.
- **Day-Ahead Unit Commitment for Reliability.** In 2018, 1.3 percent of the total day-ahead generation MWh was scheduled as must run by PJM, of which 47.3 percent received energy uplift payments.
- **Concentration of Energy Uplift Credits.** The top 10 units receiving energy uplift credits received 21.2 percent of all credits. The top 10 organizations received 74.6 percent of all credits. The HHI for day-ahead operating reserves was 8013, the HHI for balancing operating reserves was 2865 and the HHI for lost opportunity cost was 4860, all of which are classified as highly concentrated.
- **Lost Opportunity Cost Credits.** Lost opportunity cost credits increased by $37.7 million or 258.6 percent, in 2018 compared to 2017, from $14.6 million to $52.3 million. This increase was the result of combustion turbines and diesels scheduled day-ahead and not requested in real time. This increase was also a result of backing down steam and combined cycle units in order to control for the west to east transfer interfaces binding in January. Generation from combustion turbines and diesels scheduled day-ahead but not requested in real time receiving lost opportunity cost credits increased by 374 GWh or 58.6 percent in 2018, compared to 2017, from 639 GWh to 1,013 GWh.

Energy Uplift Charges

- **Energy Uplift Charges.** Total energy uplift charges increased by $72.0 million, or 56.5 percent, in 2018 compared to 2017, from $127.3 million to $199.3 million.
- **Energy Uplift Charges Categories.** The increase of $72.0 million in 2018 is comprised of a $9.2 million increase in day-ahead operating reserve charges, a $69.9 million increase in balancing operating reserve charges and a $7.3 million decrease in reactive services charges.
- **Average Effective Operating Reserve Rates in the Eastern Region.** Day-ahead load paid $0.041 per MWh, real-time load paid $0.029 per MWh, a DEC paid $0.722 per MWh and an INC and any load,

generation or interchange transaction deviation paid $0.681 per MWh.

- **Average Effective Operating Reserve Rates in the Western Region.** Day-ahead load paid $0.041 per MWh, real-time load paid $0.027 per MWh, a DEC paid $0.735 per MWh and an INC and any load, generation or interchange transaction deviation paid $0.693 per MWh.
- **Reactive Services Rates.** The ComEd, Pepco, and EKPC control zones had the three highest local voltage support rates: $0.116, $0.023 and $0.015 per MWh.

Geography of Charges and Credits

- In 2018, 88.2 percent of all uplift charges allocated regionally (day-ahead operating reserves and balancing operating reserves) were paid by transactions at control zones, 2.9 percent by transactions at hubs and aggregates, and 8.9 percent by transactions at interchange interfaces.
- Generators in the Eastern Region received 47.7 percent of all balancing generator credits, including lost opportunity cost and canceled resources credits.
- Generators in the Western Region received 50.7 percent of all balancing generator credits, including lost opportunity cost and canceled resources credits.
- External generators received 1.6 percent of all balancing generator credits, including lost opportunity cost and canceled resources credits.

Section 4 Recommendations

- The MMU recommends that uplift be paid only based on operating parameters that reflect the flexibility of the benchmark new entrant unit (CONE unit) in the PJM Capacity Market. (Priority: High. First reported Q1, 2018. Status: Not adopted.)
- 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. (Priority: Medium. First reported 2013. Status: Not adopted.)
- 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. (Priority: Medium. First reported 2015. Status: Not adopted.)
- 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. (Priority: Medium. First Reported 2016. Status: Not adopted.)
- 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. (Priority: Medium. First Reported 2012. Status: Not adopted.)
- The MMU recommends eliminating intraday segments from the calculation of uplift payments and returning to calculating the need for uplift based on the entire 24 hour operating day. (Priority: High. First reported Q1, 2018. Status: Not adopted.)
- The MMU recommends the elimination of 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. (Priority: Medium. First reported 2013. Status: Not adopted.)
- The MMU recommends enhancing the current energy uplift allocation rules to reflect the recommended elimination of day-ahead operating reserves, the timing of commitment decisions and the commitment reasons. (Priority: High. First reported 2012. Status: Not adopted.)
- The MMU recommends reincorporating the use of net regulation revenues as an offset in the calculation of balancing operating reserve credits. (Priority: Medium. First reported 2009. Status: Not adopted. Stakeholder process.)
- 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. (Priority: Low. First reported 2013. Status: Not adopted. Stakeholder process.)

- The MMU recommends three modifications to the energy lost opportunity cost calculations:
  - The MMU recommends calculating LOC based on 24 hour daily periods for combustion turbines and diesels scheduled in the Day-Ahead Energy Market, but not committed in real time. (Priority: Medium. First reported 2014. Status: Not adopted.)
  - The MMU recommends that units scheduled in the Day-Ahead Energy Market and not committed in real time should be compensated for LOC based on their real-time desired and achievable output, not their scheduled day-ahead output. (Priority: Medium. First reported 2015. Status: Not adopted.)
  - The MMU recommends that only flexible fast start units (startup plus notification times of 10 minutes or less) and short minimum run times (one hour or less) be eligible by default for the LOC compensation to units scheduled in the Day-Ahead Energy Market and not committed in real time. Other units should be eligible for LOC compensation only if PJM explicitly cancels their day-ahead commitment. (Priority: Medium. First reported 2015. Status: Not adopted.)
- The MMU recommends that up to congestion transactions be required to pay energy uplift charges for both the injection and the withdrawal sides of the UTC. (Priority: High. First reported 2011. Status: Not adopted.)
- The MMU recommends eliminating the use of internal bilateral transactions (IBTs) in the calculation of deviations used to allocate balancing operating reserve charges. (Priority: High. First reported 2013. Status: Adopted 2018.[73])
- 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. (Priority: Medium. First reported 2014. Status: Not adopted. Stakeholder process.)
- The MMU recommends that the total cost of providing reactive support be categorized and allocated as reactive services. Reactive services credits should be calculated consistent with the balancing operating reserve credit calculation. (Priority: Medium. First reported 2012. Status: Not adopted. Stakeholder process.)
- The MMU recommends including real-time exports and real-time wheels in the allocation of the cost of providing reactive support to the 500 kV system or above, in addition to real-time load. (Priority: Low. First reported 2013. Status: Not adopted.)
- The MMU recommends modifications to the calculation of lost opportunity costs credits paid to wind units. The lost opportunity costs credits paid to wind units should be based on the lesser of the desired output, the estimated output based on actual wind conditions and the capacity interconnection rights (CIRs). The MMU recommends that PJM allow wind units to request CIRs that reflect the maximum output wind units want to inject into the transmission system at any time. (Priority: Low. First reported 2012. Status: Not adopted.)
- 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 the Manual 11 attachment C procedure with the implementation of hourly offers (ER16-372-000). (Priority: Medium. First reported 2016. Status: Not adopted.[74])
- 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. (Priority: Medium. First reported 2011. Status: Partially adopted.)

73 As of November 1, 2018, internal bilateral transactions are no longer used for the calculation of deviations for purposes of allocating balancing operating reserve charges. See the *2018 State of the Market Report for PJM*, Section 3: "Energy Market" at "Internal Bilateral Transactions" for an analysis of the impact of this change on virtual bidding activity.

74 Although this recommendation has not been adopted exactly as recommended by the MMU, the implementation of hourly offers by PJM has effectively adopted this recommendation.

- 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. (Priority: High. First reported 2013. Status: Partially adopted.[75])
- The MMU recommends that PJM pay uplift based on the offer at the lower of the actual unit output or the dispatch signal MW. (Priority: Medium. First reported Q1, 2018. Status: Not adopted.)
- 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. (Priority: Medium. First reported Q1, 2018. Status: Not adopted.)
- 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 (Priority: Medium. New recommendation. Status: Not adopted.)

Section 4 Conclusion

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

It is not appropriate to accept that inflexible units should be paid or set price based on short run marginal costs plus no load. The question of why units make inflexible offers should be addressed directly. Are units inflexible because they are old and inefficient, because owners have not invested in increased flexibility or because they serve as a mechanism for the exercise of market power? The question of why the inflexible unit was built, whether it was built under cost of service regulation and whether it is efficient to retain the unit should be answered directly. The question of how to provide market incentives for investment in flexible units and for investment in increased flexibility of existing units should be addressed directly. The question of whether inflexible units should be paid uplift at all should be addressed directly. Marginal cost pricing without paying uplift to inflexible units would create incentives for market participants to provide flexible solutions including replacing inefficient units with flexible, efficient units.

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

Accurate short run price signals, equal to the short run marginal cost of generating power, provide market incentives for cost minimizing production to all economically dispatched resources and provide market incentives to load based on the marginal cost of additional consumption. The objective of efficient short run price signals is to minimize system production costs, not to minimize uplift. Repricing the market to reflect commitment costs would create a tradeoff between minimizing production costs and reduction of uplift. The tradeoff would exist because when commitment costs are included in prices, the price signal no longer equals the short run marginal cost and therefore no longer provides the correct signal for efficient behavior for market participants making decisions on the margin, whether resources, load, interchange transactions, or

75 On September 7, 2018, PJM made a compliance filing for FERC Order No. 844 to publish unit specific uplift credits. The compliance filing has not been accepted by FERC. Absent acceptance from the FERC, PJM will not begin publishing data on unit specific uplift credits.

virtual traders. This tradeoff would be created in more limited form by PJM's fast start pricing proposal (limited convex hull pricing) and in extensive form by PJM's full convex hull pricing proposal.

When units receive substantial revenues through energy uplift payments, these payments are not transparent to the market because of the current confidentiality rules. As a result, other market participants, including generation and transmission developers, do not have the opportunity to compete to displace them. As a result, substantial energy uplift payments to a concentrated group of units and organizations have persisted for more than ten years. FERC Order No. 844 authorized the publication of unit specific uplift payments for credits incurred after January 1, 2019.[76]

One part of addressing the level and allocation of uplift payments is to eliminate all day-ahead operating reserve credits. It is illogical and unnecessary to pay units day-ahead operating reserve credits because units do not incur any costs to run and any revenue shortfalls are addressed by balancing operating reserve credits.

Up to congestion transactions continue to pay no energy uplift charges, which means that all others who pay these charges are paying too much.[77]

PJM needs to pay substantially more attention to the details of uplift payments including accurately tracking whether units are following dispatch, identifying the actual need for units to be dispatched out of merit and determining whether local reserve zones or better definitions of constraints would be a more market based approach.

While energy uplift charges are an appropriate part of the cost of energy, market efficiency would be improved by ensuring that the level and variability of these charges are as low as possible consistent with the reliable operation of the system and consistent with pricing at short run marginal cost. The goal should be to minimize the total incurred energy uplift charges and to increase the transactions over which those charges are spread in order to reduce the impact of energy uplift charges on markets. The result would be to reduce the level of per MWh charges, to reduce the uncertainty associated with uplift charges and to reduce the impact of energy uplift charges on decisions about how and when to participate in PJM markets.

Overview: Section 5, Capacity Market

RPM Capacity Market

Market Design

The Reliability Pricing Model (RPM) Capacity Market is a forward-looking, annual, locational market, with a must offer requirement for Existing Generation Capacity Resources and mandatory participation by load, with performance incentives, that includes clear market power mitigation rules and that permits the direct participation of demand-side resources.[78]

Under RPM, capacity obligations are annual. Base Residual Auctions (BRA) are held for Delivery Years that are three years in the future. Effective with the 2012/2013 Delivery Year, First, Second and Third Incremental Auctions (IA) are held for each Delivery Year.[79] Prior to the 2012/2013 Delivery Year, the Second Incremental Auction was conducted if PJM determined that an unforced capacity resource shortage exceeded 100 MW of unforced capacity due to a load forecast increase. Effective January 31, 2010, First, Second, and Third Incremental Auctions are conducted 20, 10, and three months prior to the Delivery Year.[80] Also effective for the 2012/2013 Delivery Year, a Conditional Incremental Auction may be held if there is a need to procure additional capacity resulting from a delay in a planned large transmission upgrade that was modeled in the BRA for the relevant Delivery Year.[81]

The 2018/2019 RPM Third Incremental Auction, the 2021/2022 RPM Base Residual Auction, the 2019/2020 RPM Second Incremental Auction, and the 2020/2021 RPM First Incremental Auction were conducted in 2018.

On June 9, 2015, FERC accepted changes to the PJM capacity market rules proposed in PJM's Capacity

76 Publication of unit specific uplift credits will begin after FERC accepts PJM's Order No. 844 compliance filing.

77 On October 17, 2017, PJM filed with FERC a proposed tariff change to allocate uplift to UTC transactions in the same manner in which uplift is currently allocated to other virtual transactions, as a separate injection and withdrawal deviation. FERC rejected the proposed tariff change. The rejection was without prejudice and PJM has the option to submit a new proposal. See FERC Docket No. ER18-86-000. PJM has not filed a new proposal.

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

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

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

81 See 126 FERC ¶ 61,275 at P 88 (2009).

Performance (CP) filing.[82] For a transition period during the 2018/2019 and 2019/2020 Delivery Years, PJM will procure two product types, Capacity Performance and Base Capacity. PJM also procured Capacity Performance resources in two transition auctions for the 2016/2017 and 2017/2018 Delivery Years. Effective with the 2020/2021 Delivery Year, PJM will procure a single capacity product, Capacity Performance. CP Resources are expected to be available and capable of providing energy and reserves when needed at any time during the Delivery Year.[83] Effective for the 2018/2019 through the 2019/2020 Delivery Years, a Base Capacity Demand Resource Constraint and a Base Capacity Resource Constraint are established for each modeled LDA. These maximum quantities are set for reliability purpose to limit the quantity procured of the less available products, including Base Capacity Generation Resources, Base Capacity Demand Resources, and Base Capacity Energy Efficiency Resources. The Capacity Performance (CP) Transition Incremental Auctions (IAs) were held as part of a five year transition to a single capacity product type in the 2020/2021 Delivery Year. Participation in the CP Transition IAs was voluntary. If a resource cleared a CP Transition IA and had a prior commitment for the relevant delivery year, the existing commitment was converted to a CP commitment, which is subject to the CP performance requirements and nonperformance charges. The Transition IAs were not designed to minimize the cost of purchasing Capacity Performance resources for the two delivery years and were not designed to maximize economic welfare for the two delivery years.

RPM prices are locational and may vary depending on transmission constraints.[84] Existing generation capable of qualifying as a capacity resource must be offered into RPM auctions, except for resources owned by entities that elect the fixed resource requirement (FRR) option. Participation by LSEs is mandatory, except for those entities that elect the FRR option. There is an administratively determined demand curve that defines scarcity pricing levels and that, with the supply curve derived from capacity offers, determines market prices in each BRA. RPM rules provide performance incentives for generation, including the requirement to submit generator outage data and the linking of capacity payments to the level of unforced capacity, and the performance incentives have been strengthened significantly under the Capacity Performance modifications to RPM. Under RPM there are explicit market power mitigation rules that define the must offer requirement, that define structural market power based on the marginal cost of capacity, that define offer caps, that define the minimum offer price, and that have flexible criteria for competitive offers by new entrants. Market power mitigation is effective only when these definitions are up to date and accurate. Demand resources and energy efficiency resources may be offered directly into RPM auctions and receive the clearing price without mitigation.

Market Structure

- **RPM Installed Capacity.** During 2018, RPM installed capacity increased 2,069.3 MW or 1.1 percent, from 183,882.4 MW on January 1 to 185,951.7 MW on December 31. Installed capacity includes net capacity imports and exports and can vary on a daily basis.
- **RPM Installed Capacity by Fuel Type.** Of the total installed capacity on December 31, 2018, 40.2 percent was gas; 32.7 percent was coal; 17.6 percent was nuclear; 4.8 percent was hydroelectric; 3.4 percent was oil; 0.6 percent was wind; 0.4 percent was solid waste; and 0.3 percent was solar.
- **Market Concentration.** In the 2018/2019 RPM Third Incremental Auction, 2019/2020 RPM Second Incremental Auction, 2021/2022 RPM Base Residual Auction, and the 2020/2021 RPM First Incremental Auction all participants in the total PJM market as well as the LDA RPM markets failed the three pivotal supplier (TPS) test.[85] Offer caps were applied to all sell offers for resources which were subject to mitigation when the Capacity Market Seller did not pass the test, the submitted sell offer exceeded the defined offer cap, and the submitted sell offer,

82 See 151 FERC ¶ 61,208 (2015).

83 See "PJM Manual 18: PJM Capacity Market," § 1.5, Rev. 41 (Jan. 1, 2019) at p 19.

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

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

absent mitigation, increased the market clearing price.[86 87 88]

- **Imports and Exports.** Of the 4,470.4 MW of imports in the 2021/2022 RPM Base Residual Auction, 4,051.8 MW cleared. Of the cleared imports, 1,909.9 MW (47.1 percent) were from MISO.
- **Demand-Side and Energy Efficiency Resources.** Capacity in the RPM load management programs was 10,798.7 MW for June 1, 2018, as a result of cleared capacity for demand resources and energy efficiency resources in RPM auctions for the 2018/2019 Delivery Year (13,731.7 MW) less replacement capacity (2,933.0 MW).

Market Conduct

- **2018/2019 RPM Base Residual Auction.** Of the 473 generation resources that submitted Base Capacity offers, the MMU calculated offer caps for 219 generation resources (46.3 percent), of which 166 (35.1 percent) were based on the technology specific default (proxy) ACR values and 53 (11.2 percent) were unit-specific offer caps. Of the 992 generation resources that submitted Capacity Performance offers, the MMU calculated unit specific offer caps for 35 generation resources (3.5 percent).
- **2018/2019 RPM First Incremental Auction.** Of the 80 generation resources that submitted Base Capacity offers, the MMU calculated offer caps for 30 generation resources (37.5 percent), of which 18 (22.5 percent) were based on the technology specific default (proxy) ACR values and 12 (15.0 percent) were unit-specific offer caps. Of the 293 generation resources that submitted Capacity Performance offers, the MMU calculated unit specific offer caps for nine generation resources (3.1 percent).
- **2018/2019 RPM Second Incremental Auction.** Of the 68 generation resources that submitted Base Capacity offers, the MMU calculated offer caps for 23 generation resources (33.8 percent), of which 12 (17.6 percent) were based on the technology specific default (proxy) ACR values and 11 (16.2 percent) were unit-specific offer caps. Of the 344 generation resources that submitted Capacity Performance offers, the MMU calculated unit specific offer caps for five generation resources (1.5 percent).
- **2018/2019 RPM Third Incremental Auction.** Of the 211 generation resources that submitted Base Capacity offers, the MMU calculated offer caps for five generation resources (2.4 percent), of which one (0.5 percent) was based on the technology specific default (proxy) ACR values and four (1.9 percent) were unit-specific offer caps. Of the 495 generation resources that submitted Capacity Performance offers, the MMU calculated unit specific offer caps for three generation resources (0.6 percent).
- **2019/2020 RPM Base Residual Auction.** Of the 505 generation resources that submitted Base Capacity offers, the MMU calculated offer caps for 212 generation resources (42.0 percent), of which 171 (33.9 percent) were based on the technology specific default (proxy) ACR values and 41 (8.1 percent) were unit-specific offer caps. Of the 1,003 generation resources that submitted Capacity Performance offers, the MMU calculated unit specific offer caps for 25 generation resources (2.5 percent).
- **2019/2020 RPM First Incremental Auction.** Of the 81 generation resources that submitted Base Capacity offers, the MMU calculated offer caps for 28 generation resources (34.6 percent), of which 17 (21.0 percent) were based on the technology specific default (proxy) ACR values and 11 (13.6 percent) were unit-specific offer caps. Of the 382 generation resources that submitted Capacity Performance offers, the MMU calculated unit specific offer caps for six generation resources (1.6 percent).
- **2019/2020 RPM Second Incremental Auction.** Of the 72 generation resources that submitted Base Capacity offers, the MMU calculated unit specific offer caps for eight generation resources (11.1 percent). Of the 409 generation resources that submitted Capacity Performance offers, the MMU calculated unit specific offer caps for six generation resources (1.5 percent).
- **2020/2021 RPM Base Residual Auction.** Of the 1,114 generation resources that submitted Capacity Performance offers, the MMU calculated unit specific offer caps for 14 generation resources (1.3 percent).

86 See OATT Attachment DD § 6.5.

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

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

- **2020/2021 RPM First Incremental Auction.** Of the 397 generation resources that submitted Capacity Performance offers, the MMU calculated unit specific offer caps for eight generation resources (2.0 percent).
- **2021/2022 RPM Base Residual Auction.** Of the 1,132 generation resources that submitted Capacity Performance offers, the MMU calculated unit specific offer caps for eight generation resources (0.7 percent).
  - The conduct of some participants was determined to be not competitive.

Market Performance

- The 2018/2019 RPM Third Incremental Auction, the 2021/2022 RPM Base Residual Auction, the 2019/2020 RPM Second Incremental Auction, and the 2020/2021 RPM First Incremental Auction were conducted in 2018. The weighted average capacity price for the 2018/2019 Delivery Year is $172.09, including all RPM auctions for the 2018/2019 Delivery Year held 2018. The weighted average capacity price for the 2019/2020 Delivery Year is $112.63, including all RPM auctions for the 2019/2020 Delivery Year held through 2018.
- For the 2018/2019 Delivery Year, RPM annual charges to load are $11.0 billion.
- In the 2021/2022 RPM Base Residual Auction, market performance was determined to be not competitive as a result of noncompetitive offers that affected market results.

Reliability Must Run Service

- Of the seven companies (23 units) that have provided RMR service, two companies (seven units) filed to be paid for RMR service under the deactivation avoidable cost rate (DACR), the formula rate. The other five companies (16 units) filed to be paid for RMR service under the cost of service recovery rate.

Generator Performance

- **Forced Outage Rates.** The average PJM EFORd for 2018 was 7.2 percent, an increase from 7.1 percent for 2017.[89]
- **Generator Performance Factors.** The PJM aggregate equivalent availability factor for 2018 was 83.2 percent, a decrease from 83.9 percent for 2017.
- **Outages Deemed Outside Management Control (OMC).** In 2018, 1.2 percent of forced outages were classified as OMC outages.

Section 5 Recommendations[90]

The MMU recognizes that PJM has implemented the Capacity Performance Construct to replace some of the existing core market rules and to address fundamental performance incentive issues. The MMU recognizes that the Capacity Performance Construct addresses many of the MMU's recommendations. The MMU's recommendations are based on the existing capacity market rules. The status is reported as adopted if the recommendation was included in FERC's order approving PJM's Capacity Performance filing.[91]

Definition of Capacity

- 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.[92] [93] (Priority: High. First reported 2013. Status: Not adopted.)

89 The generator performance analysis includes all PJM capacity resources for which there are data in the PJM generator availability data systems (GADS) database. This set of capacity resources may include generators in addition to those in the set of generators committed as capacity resources in RPM. Data was downloaded from the PJM GADS database on February 1, 2019. EFORd data presented in state of the market reports may be revised based on data submitted after the publication of the reports as generation owners may submit corrections at any time with permission from PJM GADS administrators.

90 The MMU has identified serious market design issues with RPM and the MMU has made specific recommendations to address those issues. These recommendations have been made in public reports. See Table 52.

91 151 FERC ¶ 61,208 (2015).

92 See also Comments of the Independent Market Monitor for PJM, Docket No. ER14-503-000 (December 20, 2013).

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

- The MMU recommends that DR providers be required to have a signed contract with specific customers for specific facilities for specific levels of DR at least six months prior to any capacity auction in which the DR is offered. (Priority: High. First reported 2016. Status: Not adopted.)

Market Design and Parameters

- The MMU recommends that the test for determining modeled Locational Deliverability Areas (LDAs) in RPM be redefined. A detailed reliability analysis of all at risk units should be included in the redefined model. (Priority: Medium. First reported 2013. Status: Not adopted.)
- The MMU recommends that the net revenue calculation used by PJM to calculate the net Cost of New Entry (CONE) VRR parameter reflect the actual flexibility of units in responding to price signals rather than using assumed fixed operating blocks that are not a result of actual unit limitations.[94] [95] The result of reflecting the actual flexibility is higher net revenues, which affect the parameters of the RPM demand curve and market outcomes. (Priority: High. First reported 2013. Status: Not adopted.)
- 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 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, there is no reason to have an add back mechanism. If EE remains on the supply side, the implementation of the EE add back mechanism should be modified to ensure that market clearing prices are not affected. (Priority: Medium. First reported 2016. Status: Not adopted.)
- The MMU recommends that PJM reduce the number of incremental auctions to a single incremental auction held three months prior to the start of the delivery year and reevaluate the triggers for holding conditional incremental auctions. (Priority: Medium. First reported 2013. Status: Not adopted.)
- The MMU recommends that PJM offer to sell back capacity in incremental auctions only at the BRA clearing price for the relevant delivery year. (Priority: Medium. First reported 2017. Status: Not adopted.)
- The MMU recommends changing the RPM solution method to explicitly incorporate the cost of make whole payments in the objective function. (Priority: Medium. First reported 2014. Status: Not adopted.)
- The MMU recommends that PJM clear the capacity market based on nodal capacity resource locations and the characteristics of the transmission system consistent with the actual electrical facts of the grid. 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. (Priority: Medium. First reported 2017. Status: Not adopted.)

Offer Caps, Offer Floors, and Must Offer

- The MMU recommends use of the Sustainable Market Rule (SMR) in order to protect competition in the capacity market from nonmarket revenues.[96] (Priority: High. First reported 2016. Status: Not adopted.)
- The MMU recommends that, as part of the MOPR unit specific standard of review, all projects be required to use the same basic modeling assumptions. That is the only way to ensure that projects compete on the basis of actual costs rather than on the basis

94 See PJM Interconnection, L.L.C., Docket No. ER12-513-000 (December 1, 2011) ("Triennial Review").
95 See the *2017 State of the Market Report for PJM*, Volume 2, Section 7: Net Revenue.

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

of modeling assumptions.[97] (Priority: High. First reported 2013. Status: Not adopted.)

- The MMU recommends that modifications to existing resources not be treated as new resources for purposes of market power related offer caps or MOPR offer floors. (Priority: Low. First reported 2012. Status: Not adopted.)
- The MMU recommends that the RPM market power mitigation rule be modified to apply offer caps in all cases when the three pivotal supplier test is failed and the sell offer is greater than the offer cap. This will ensure that market power does not result in an increase in make whole payments. (Priority: Medium. First reported 2017. Status: Not adopted.)
- 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 reserve margins, and other assumptions consistent with the annual IRM study. (Priority: High. First reported 2017. Status: Not adopted.)
- 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. (Priority: High. First reported 2017. Status: Not adopted.)
- 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. (Priority: Medium. First reported Q3, 2018. Status: Not adopted.)

Performance Incentive Requirements of RPM

- The MMU recommends that a unit which is not capable of supplying energy consistent with its day-ahead offer reflect an appropriate outage. (Priority: Medium. First reported 2009. Status: Not adopted.)
- The MMU recommends that retroactive replacement transactions associated with a failure to perform during a PAH not be allowed and that, more generally, retroactive replacement capacity transactions not be permitted. (Priority: Medium. First reported 2016. Status: Not adopted.)
- The MMU recommends that there be an explicit requirement that capacity resource offers in the Day-Ahead Energy Market be competitive, where competitive is defined to be the short run marginal cost of the units. (Priority: Low. First reported 2013. Status: Not adopted.)

Capacity Imports and Exports

- 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. (Priority: High. First reported 2016. Status: Not adopted.)
- The MMU recommends that all costs incurred as a result of a pseudo tied unit be borne by the unit itself and included as appropriate in unit offers in the capacity market. (Priority: High. First reported 2016. Status: Not adopted.)
- 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. (Priority: Low. First reported 2010. Status: Partially adopted.)

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

Deactivations/Retirements

- The MMU recommends that the notification requirement for deactivations be extended from 90 days prior to the date of deactivation to 12 months prior to the date of deactivation and that PJM and the MMU be provided 60 days rather than 30 days to complete their reliability and market power analyses. (Priority: Low. First reported 2012. Status: Partially adopted.)
- The MMU recommends that 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. (Priority: Low. First reported 2010. Status: Not adopted.)
- 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. (Priority: Medium. First reported 2017. Status: Not adopted.)

Section 5 Conclusion

The analysis of PJM Capacity Markets begins with market structure, which provides the framework for the actual behavior or conduct of market participants. The analysis examines participant behavior within that market structure. In a competitive market structure, market participants are constrained to behave competitively. The analysis examines market performance, measured by price and the relationship between price and marginal cost, that results from the interaction of market structure and participant behavior. Market power is and will remain endemic to the structure of the PJM Capacity Market. Nonetheless a competitive outcome can be assured by appropriate market power mitigation rules.

The MMU concludes that the 2021/2022 RPM Base Residual Auction results were not competitive as a result of offers above the competitive level by some market participants. The MMU recognizes that these market participants followed the capacity market rules by offering at less than the stated offer cap of Net CONE times B. But Net CONE times B is not a competitive offer when the expected number of performance assessment intervals is zero or a very small number and the non-performance charge rate is defined as Net CONE/30. Under these circumstances, a competitive offer, under the logic defined in PJM's capacity performance filing, is net ACR. That is the way in which most market participants offered in this and prior capacity performance auctions.

The FERC approved PJM tariff defines the offer cap as Net CONE times B, rather than including the full logic supporting the definition of the offer cap under the capacity performance paradigm. If the tariff had defined the offer cap consistent with PJM's filing in the capacity performance matter, the offer cap would have been net ACR rather than Net CONE times B.

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

The MMU found serious market structure issues, measured by the three pivotal supplier test results in the PJM Capacity Market in 2018. Explicit market power mitigation rules in the RPM construct only partially offset the underlying market structure issues in the PJM Capacity Market under RPM. In the 2021/2022 RPM Base Residual Auction, the default offer cap of net CONE times B exceeded the competitive offer for a number of resources. Some seasonal resources were paid additional make whole based on a failure of the market power rules to apply offer capping.

The MMU has identified serious market design issues with RPM and the MMU has made specific recommendations to address those issues.[98] [99] [100] [101] [102] [103] [104] In 2017 and 2018, the MMU prepared a number of RPM related reports and testimony, shown in Table 5-2. The capacity performance modifications to the RPM construct have significantly improved the capacity market and addressed many of the issues identified by the MMU. The MMU will continue to publish more detailed reports on the CP auctions which include more specific issues and suggestions for improvements.

The PJM markets have worked to provide incentives to entry and to retaining capacity. PJM had excess reserves of more than 9,000 MW on June 1, 2018, and will have excess reserves of more than 17,000 MW on June 1, 2019, based on current positions.[105] Capacity investments in PJM were financed by market sources. Of the 30,881.7 MW of additional capacity that cleared in RPM auctions for the 2007/2008 through 2017/2018 delivery years, 22,419.7 MW (72.6 percent) were based on market funding. Of the 13,553.8 MW of additional capacity that cleared in RPM auctions for the 2018/2019 through 2021/2022 delivery years, 11,752.4 MW (86.7 percent) are based on market funding. Those investments were made based on the assumption that markets would be allowed to work and that inefficient units would exit.

The issue of external subsidies emerged more fully in 2017 and 2018. The subsidies are not part of the PJM market design but nonetheless threaten the foundations of the PJM capacity market as well as the competitiveness of PJM markets overall.

The Ohio subsidy proceedings, the Illinois ZEC legislation to subsidize the Quad Cities nuclear power plant, the request in Pennsylvania to subsidize the Three Mile Island nuclear power plant, the New Jersey legislation to subsidize the Salem and Hope Creek nuclear power plants, the potential U.S. DOE proposal to subsidize coal and nuclear power plants, and the request by FirstEnergy to the U.S. DOE for subsidies consistent with the DOE Grid Resilience Proposal, all originate from the fact that competitive markets result in the exit of uneconomic and uncompetitive generating units. Regardless of the specific rationales offered by unit owners, the proposed solution for all such generating units has been to provide out of market subsidies in order to retain such units. The proposed solution in all cases ignores the opportunity cost of subsidizing uneconomic units, which is the displacement of new resources and technologies that would otherwise be economic. These subsidies are not accurately characterized as state subsidies. These subsidies were all requested by the owners of specific uneconomic generating units in order to improve the profitability of those specific units. These subsidies were not requested to accomplish broader social goals. Broader social goals can all be met with market-based mechanisms available to all market participants on a competitive basis and without discrimination.

Subsidies are contagious. Competition in the markets could be replaced by competition to receive subsidies. Similar threats to competitive markets are being discussed by unit owners in other states and the potentially precedential nature of these actions enhances the urgency of creating an effective rule to maintain competitive markets by modifying market rules to address these subsidies.

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

A sustainable competitive wholesale power market must recognize three salient structural elements: state nonmarket revenues for renewable energy; a significant level of generation resources subject to cost of service

98 See "Analysis of the 2017/2018 RPM Base Residual Auction," <http://www.monitoringanalytics.com/reports/Reports/2014/IMM_Analysis_of_the_2017_2018_RPM_Base_Residual_Auction_20141006.pdf> (October 6, 2014).

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

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

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

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

103 See "Analysis of Replacement Capacity for RPM Commitments: June 1, 2007 to June 1, 2016," <http://www.monitoringanalytics.com/reports/Reports/2016/IMM_Analysis_of_Replacement_Capacity_for_RPM_Commitments_06012007_to_06012016_20161227.pdf> (December 27, 2016).

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

105 The calculated reserve margin for June 1, 2019, does not account for cleared buy bids that have not been used in replacement capacity transactions.

regulation; and the structure and performance of the existing market based generation fleet.

Subsidies to specific resources that are uneconomic as a result of competition are an effort to reverse market outcomes with no commitment to a regulatory model and no attempt to mitigate negative impacts on competition. The unit specific subsidy model is inconsistent with the PJM market design and inconsistent with the market paradigm and constitutes a significant threat to both.

The existing FRR approach remains an option for utilities with regulated revenues based on cost of service rates, including both privately and publicly owned (including public power entities and electric cooperatives) utilities. Such regulated utilities have had and continue to have the ability to opt out of the capacity market and provide their own capacity.

Given that states have increasingly aggressive renewable energy targets, a core goal of a competitive market design should be to ensure that the resources required to provide reliability receive appropriate competitive market incentives for entry and for ongoing investment and for exit when uneconomic. A significant level of renewable resources, operating with zero or near zero marginal costs, will result in very low energy prices. Since renewable resources are intermittent, the contribution of renewables to meeting reliability targets must be analyzed carefully to ensure that the capacity value is calculated correctly.

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

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

The expected impact of the SMR design on the offers and clearing of renewable resources and nuclear plants would be from zero to insignificant. The competitive offers of renewables, based on the net ACR of current technologies, are likely to clear in the capacity market. The competitive offers of nuclear plants, based on net ACR, are likely to clear in the capacity market.

Cost of service resources have the option of using the existing FRR rules, which would allow regulated utilities to opt out of the capacity market. The expected impact of the SMR design on the offers and clearing of regulated cost of service resources that remained in the capacity market would be from zero to insignificant. The competitive offers of these resources, based on net ACR, are likely to clear in the capacity market.

To the extent that there are shared broader goals related to PJM markets, they should also be addressed, but this can happen with a slightly longer lead time. If a shared goal is to reduce carbon output, a price on carbon is the market based solution. If a shared goal is increased renewables in addition to their carbon attributes, a common approach to RECs would be a market based solution. Fuel diversity has also been mentioned as an issue. Current fuel diversity is higher than ever in PJM. If there is an issue, the real issue is fuel security and not fuel diversity. Significant reliance on specific fuels, including nuclear, coal and gas means that markets are at risk from a significant disruption in any one fuel. If fuel security for gas is a concern, a number of issues should be considered including the reliability of the pipelines, the compatibility of the gas pipeline and the merchant generator business models, the degree to which electric generators have truly firm gas service and the need for a gas RTO to help ensure reliability.

As a result of the fact that demand side resources have contributed to price suppression in PJM capacity markets, the place of demand side in PJM should be reexamined. There are ways to ensure and enhance the vibrancy of demand side without negatively affecting markets for generation. There are other price formation issues in the capacity market that should also be examined and addressed.

Overview: Section 6, Demand Response

- **Demand Response Activity.** Demand response activity includes economic demand response (economic resources), emergency and pre-emergency demand response (demand resources), synchronized reserves and regulation. Economic demand response participates in the energy market. Emergency and pre-emergency demand response participates in the capacity market and energy market.[106] Demand response resources participate in the Synchronized Reserve Market. Demand response resources participate in the Regulation Market.

  In 2018, total demand response revenue increased by $95.9 million, 19.1 percent, from $502.7 million in 2017 to $598.6 million in 2018. Emergency demand response revenue accounted for 98.1 percent of all demand response revenue, economic demand response for 0.4 percent, demand response in the Synchronized Reserve Market for 1.0 percent and demand response in the regulation market for 0.5 percent.

  Total emergency demand response revenue increased by $91.8 million, 18.5 percent, from $495.2 million in 2017 to $587.0 million in 2018. This increase consisted entirely of capacity market revenue.[107]

  Economic demand response revenue decreased by $0.1 million, 3.9 percent, from $2.7 million in 2017 to $2.6 million in 2018.[108] Demand response revenue in the Synchronized Reserve Market increased by $2.9 million, 98.4 percent, from $3.0 million in 2017 to $5.9 million in 2018. Demand response revenue in the regulation market increased by $1.2 million, 66.1 percent, from $1.8 million in 2017 to $3.1 million in 2018.

- **Demand Response Energy Payments are Uplift.** Energy payments to emergency and economic demand response resources are uplift. LMP does not cover energy payments although emergency and economic demand response can and does set LMP. Energy payments to emergency demand resources are paid by PJM market participants in proportion to their net purchases in the real-time market. Energy payments to economic demand resources are paid by real-time exports from PJM and real-time loads in each zone for which the load-weighted average real-time LMP for the hour during which the reduction occurred is greater than or equal to the net benefits test price for that month.[109]

- **Demand Response Market Concentration.** The ownership of economic demand response resources was highly concentrated in 2017 and 2018. The HHI for economic resource reductions decreased by 40 points from 7590 in 2017 to 7540 in 2018. The ownership of emergency demand response resources was moderately concentrated in 2018. The HHI for emergency demand response committed MW was 1433 for the 2017/2018 Delivery Year and 1922 for the 2018/2019 Delivery Year. In the 2017/2018 Delivery Year, the four largest companies owned 69.6 percent of all committed emergency demand response MW. In the 2018/2019 Delivery Year, the four largest companies owned 77.9 percent of all committed emergency demand response MW.

- **Limited Locational Dispatch of Demand Resources.** Beginning with the 2014/2015 Delivery Year, demand resources are dispatchable for mandatory reductions on a subzonal basis, defined by zip codes, but only if the subzone is defined at least one day before it is dispatched and only until PJM removes the definition of the subzone. Nodal dispatch of demand resources in a nodal market would improve market efficiency. The goal should be nodal dispatch of demand resources with no advance notice required, as is the case for generation resources. With full implementation of the Capacity Performance rules in the capacity market starting with the 2020/2021 Delivery Year, PJM will be able to individually dispatch demand resources with no advanced notice although PJM does not know the nodal location of demand resources.

Section 6 Recommendations

The MMU recognizes that PJM incorporated some of the recommendations related to demand response in

106 Emergency demand response refers to both emergency and pre-emergency demand response. With the implementation of the Capacity Performance design, there is no functional difference between the emergency and pre-emergency demand response resource.

107 The total credits and MWh numbers for demand resources were calculated as of March 1, 2019 and may change as a result of continued PJM billing updates.

108 Economic credits are synonymous with revenue received for reductions under the economic load response program.

109 "PJM Manual 28: Operating Agreement Accounting," § 11.2.2, Rev. 81 (Oct. 25, 2018).

the Capacity Performance filing. The status of each recommendation reflects the status at December 31, 2018.

- The MMU recommends, as a preferred alternative to including demand resources as supply in the capacity market, that demand resources be on the demand side of the markets, that customers be able to avoid capacity and energy charges by not using capacity and energy at their discretion, that customer payments be determined only by metered load, and that PJM forecasts immediately incorporate the impacts of demand side behavior. (Priority: High. First reported 2014. Status: Not adopted.)
- The MMU recommends that the option to specify a minimum dispatch price (strike price) for demand resources be eliminated and that participating resources receive the hourly real-time LMP less any generation component of their retail rate. (Priority: Medium. First reported 2010. Status: Not adopted.)
- The MMU recommends that the maximum offer for demand resources be the same as the maximum offer for generation resources. (Priority: Medium. First reported 2013. Status: Not adopted.)
- The MMU recommends that the demand resources be treated as economic resources, responding to economic price signals like other capacity resources. The MMU recommends that demand resources not be treated as emergency resources, not trigger a PJM emergency and not trigger a Performance Assessment Interval. (Priority: High. First reported 2012. Status: Not adopted.)
- The MMU recommends that the Emergency Program Energy Only option be eliminated because the opportunity to receive the appropriate energy market incentive is already provided in the economic program. (Priority: Low. First reported 2010. Status: Not adopted.)
- The MMU recommends that, if demand resources remain in the capacity market, a daily energy market must offer requirement apply to demand resources, comparable to the rule applicable to generation capacity resources.[110] (Priority: High. First reported 2013. Status: Not adopted.)
- The MMU recommends that demand resources be required to provide their nodal location, comparable to generation resources. (Priority: High. First reported 2011. Status: Not adopted.)
- The MMU recommends that PJM require nodal dispatch of demand resources with no advance notice required or, if nodal location is not required, subzonal dispatch of demand resources with no advance notice required. (Priority: High. First reported 2015. Status: Not adopted.)
- The MMU recommends that PJM not remove any defined subzones and maintain a public record of all created and removed subzones. (Priority: Low. First reported 2016. Status: Not adopted.)
- The MMU recommends that PJM eliminate the measurement of compliance across zones within a compliance aggregation area (CAA). The multiple zone approach is less locational than the zonal and subzonal approach and creates larger mismatches between the locational need for the resources and the actual response. (Priority: High. First reported 2015. Status: Not adopted.)
- The MMU recommends that measurement and verification methods for demand resources be modified to reflect compliance more accurately. (Priority: Medium. First reported 2009. Status: Not adopted.)
- The MMU recommends that compliance rules be revised to include submittal of all necessary hourly load data, and that negative values be included when calculating event compliance across hours and registrations. (Priority: Medium. First reported 2012. Status: Not adopted.)
- The MMU recommends that PJM adopt the ISO-NE five-minute metering requirements in order to ensure that dispatchers have the necessary information for reliability and that market payments to demand resources be calculated based on interval meter data at the site of the demand reductions.[111] (Priority: Medium. First reported 2013. Status: Not adopted.)

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

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

- The MMU recommends 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. (Priority: Medium. First reported 2013. Status: Partially adopted.)
- The MMU recommends that load management testing be initiated by PJM with limited warning to CSPs in order to more accurately represent the conditions of an emergency event. (Priority: Low. First reported 2012. Status: Not adopted.)
- The MMU recommends that shutdown cost be defined as the cost to curtail load for a given period that does not vary with the measured reduction or, for behind the meter generators, be the start cost defined in Manual 15 for generators. (Priority: Low. First reported 2012. Status: Not adopted.)
- The MMU recommends that the Net Benefits Test be eliminated and that demand response resources be paid LMP less any generation component of the applicable retail rate. (Priority: Low. First reported 2015. Status: Not adopted.)
- The MMU recommends that the tariff rules for demand response clarify that a resource and its CSP, if any, must notify PJM of material changes affecting the capability of the resource to perform as registered and must terminate or modify registrations that are no longer capable of responding to PJM dispatch directives at defined levels because load has been reduced or eliminated, as in the case of bankrupt and/or out of service facilities. (Priority: Medium. First reported 2015. Status: Not adopted.)
- The MMU recommends that there be only one demand response product in the capacity market, with an obligation to respond when called for any hour of the delivery year. (Priority: High. First reported 2011. Status: Partially adopted.[112])
- The MMU recommends that the lead times for demand resources be shortened to 30 minutes with an hour minimum dispatch for all resources. (Priority: Medium. First reported 2013. Status: Partially adopted.)
- The MMU recommends setting the baseline for measuring capacity compliance under winter compliance at the customers' PLC, similar to GLD, to avoid double counting. (Priority: High. First reported 2010. Status: Partially adopted.)
- The MMU recommends the Relative Root Mean Squared Test be required for all demand resources with a CBL. (Priority: Low. First reported 2017. Status: Partially adopted.)
- The MMU recommends that PRD be required to respond during a PAI to be consistent with all CP resources. (Priority: High. First reported 2017. Status: Not adopted.)
- The MMU recommends that the limits imposed on the pre-emergency and emergency demand response share of the Synchronized Reserve Market be eliminated. (Priority: Medium. New recommendation. Status: Not adopted.)
- The MMU recommends that 30 minute pre-emergency and emergency demand response be considered to be 30 minute reserves. (Priority: Medium. New recommendation. Status: Not adopted.)
- 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 with the existing lag. (Priority: Medium. New recommendation. Status: Not adopted.)

Section 6 Conclusion

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

112 PJM's Capacity Performance design requires resources to respond when called for any hour of the delivery year.

on how customers value the power and on the actual cost of that power.

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

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

In order to be a substitute for generation, demand resources should be defined in PJM rules as an economic resource, as generation is defined. Demand resources should be required to offer in the Day-Ahead Energy Market and should be called when the resources are required and prior to the declaration of an emergency. Demand resources should be available for every hour of the year. The fact that PJM currently defines demand resources as emergency resources and the fact that calling on demand resources triggers a performance assessment interval (PAI) under the Capacity Performance design, both serve as a significant disincentive to calling on demand resources and mean that demand resources are underused. Demand resources should be treated as economic resources like any other capacity resource. Demand resources should be called when economic and paid the LMP rather than an inflated strike price up to $1,849 per MWh that is set by the seller.

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

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

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

In order to be a substitute for generation, reductions should be calculated hourly for dispatched DR. The current rules use the average reduction for the duration of an event. The average reduction across multiple hours does not provide an accurate metric for each hour of the event and is inconsistent with the measurement of generation resources. Measuring compliance hourly would provide accurate information to the PJM system. Under the new CP rules, the performance of demand response during Performance Assessment Interval (PAI) will be measured on a five-minute basis.

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

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

The MMU peak shaving proposal at the Summer-Only Demand Response Senior Task Force (SODRSTF) is an example of how to create a demand side product that is on the demand side of the market and not on the supply side.[113] The MMU proposal was based on the BGE load forecasting program and Pennsylvania Act 129 Utility Program.[114] [115] Under the MMU proposal, participating load would inform PJM prior to an RPM auction of the MW participating, the months and hours of participation and the temperature humidity index (THI) threshold at which load would be reduced. PJM would reduce the load forecast used in the RPM auction based on the designated reductions. Load would agree to curtail demand to at or below a defined FSL, less than the customer PLC, when the THI exceeds a defined level or load exceeds a specified threshold. By relying on metered load and the PLC, load can reduce its demand for capacity and that reduction can be verified without complicated and inaccurate metrics to estimate load reductions. Under PJM's weakened version of the program, performance will be measured under the current economic demand response CBL rules which means relying on load estimates rather than actual metered load.[116] PJM's proposal includes only a THI curtailment trigger and not an overall load curtailment trigger.

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

Under this approach, customers that wish to avoid capacity payments would reduce their load during expected high load hours. Capacity costs would be assigned to LSEs and by LSEs to customers, based on actual load on the system during these critical hours. Customers wishing to avoid high energy prices would reduce their load during high price hours. Customers would pay for what they actually use, as measured by meters, rather than relying on flawed measurement and verification methods. No M&V estimates are required. No promises of future reductions which can only be verified by M&V are required. To the extent that customers enter into contracts with CSPs or LSEs to manage their payments, M&V can be negotiated as part of a bilateral commercial contract between a customer and its CSP or LSE.

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

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

This approach would work under the CP design in the capacity market. This approach is entirely consistent with the Supreme Court decision in *EPSA* as it does not depend on whether FERC has jurisdiction over the demand side. This approach will allow FERC to more fully realize its overriding policy objective to create

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

114 *Advance signals that can be used to foresee demand response days*, BGE, <https://www.pjm.com/-/media/committees-groups/task-forces/sodrstf/20180309/20180309-item-05-bge-load-curtailment-programs.ashx> (Accessed March 6, 2019).

115 *Pennsylvania ACT 129 Utility Program*, CPower, <https://www.pjm.com/-/media/committees-groups/task-forces/sodrstf/20180413/20180413-item-03-pa-act-129-program.ashx>, (Accessed March 6, 2019).

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

competitive and efficient wholesale energy markets. The decision of the Supreme Court addressed jurisdictional issues and did not address the merits of FERC's approach. The Supreme Court's decision has removed the uncertainty surrounding the jurisdictional issues and created the opportunity for FERC to revisit its approach to demand side.

Overview: Section 7, Net Revenue

Net Revenue

- Energy net revenues are significantly affected by energy prices and fuel prices. Energy prices and fuel prices were higher in 2018 than in 2017. Energy prices increased more than gas prices in most locations except for Texas Eastern M-3 gas and CTs and CCs ran with higher margins as a result. Coal prices increased by less than gas prices and CPs ran for more hours and at higher margins in 2018 than in 2017.
- In 2018, average energy market net revenues increased by 39 percent for a new CT, 48 percent for a new CC, 138 percent for a new CP, 32 percent for a new nuclear plant, 255 percent for a new DS, 24 percent for a new on shore wind installation, 26 percent for a new off shore wind installation and 10 percent for a new solar installation compared to 2017.
- The relative prices of fuel varied during 2018. While the marginal cost of the new CC was consistently below that of the new CP in 2018, the marginal cost of the new CT was above that of the new CP in January and December.
- Capacity revenue accounted for 47 percent of total net revenues for a new CT, 36 percent for a new CC, 48 percent for a new CP, 87 percent for a new DS, and 21 percent for a new nuclear plant.
- In 2018, a new CT would have received sufficient net revenue to cover levelized total costs in 11 zones and would have covered at least 87 percent of levelized costs in all zones as a result of higher energy prices and higher locational capacity market prices.
- In 2018, a new CC would have received sufficient net revenue to cover levelized total costs in all zones.
- In 2018, a new CP would not have received sufficient net revenue to cover levelized total costs in any zone.
- In 2018, a new nuclear plant would not have received sufficient net revenue to cover levelized total costs in any zone.
- In 2018, net revenues covered more than 64 percent of the annual levelized total costs of a new entrant on shore wind installation in AEP, APS, ComEd and PENELEC. Renewable energy credits accounted for at least 30 percent of the total net revenue of an on shore wind installation.
- In 2018, net revenues covered 49 percent of the annual levelized total costs of a new entrant off shore wind installation in AECO. Renewable energy credits accounted for 31 percent of the total net revenue of an off shore wind installation.
- In 2018, net revenues covered more than 100 percent of the annual levelized total costs of a new entrant solar installation in AECO, Dominion, JCPL and PSEG. Renewable energy credits accounted for at least 64 percent of the total net revenue of a solar installation.
- In 2018, most units did not achieve full recovery of avoidable costs through net revenue from energy markets alone, illustrating the critical role of the PJM Capacity Market in providing incentives for continued operation and investment. In 2018, capacity revenues were sufficient to cover the shortfall between energy revenues and avoidable costs for the majority of units and technology types in PJM, with the exception of some coal units and some nuclear units.
- Using a forward analysis, a total of 14,954 MW of coal and nuclear capacity are at risk of retirement, in addition to the units that are currently planning to retire. The 14,954 MW considered to be at risk of retirement consists of 12,017 MW of coal and 2,937 MW of nuclear capacity.

Historical New Entrant CT and CC Revenue Adequacy

Total unit net revenues include energy and capacity revenues. Analysis of the total unit revenues of theoretical new entrant CTs and CCs for three representative locations shows that CT and CC units that entered the

PJM markets in 2007 have not covered their total costs, including the return on and of capital, on a cumulative basis. The analysis also shows that theoretical new entrant CTs and CCs that entered the PJM markets in 2012 have covered their total costs on a cumulative basis in the eastern PSEG and BGE zones but have not covered total costs in the western ComEd Zone. Energy market revenues alone were not sufficient to cover total costs in any scenario, which demonstrates the critical role of the capacity market revenue in covering total costs.

Section 7 Conclusion

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

Unlike cost of service regulation, markets do not guarantee that units will cover their costs. CC units that entered the PJM markets in 2007 have covered their total costs, including the return on and of capital, on a cumulative basis in the eastern PSEG and BGE zones but have not covered total costs in the western ComEd Zone. The analysis also shows that theoretical new entrant CTs and CCs that entered the PJM markets in 2012 have covered their total costs on a cumulative basis in the eastern PSEG and BGE zones but have not covered total costs in the western ComEd Zone.

Overview: Section 8, Environmental and Renewables

Federal Environmental Regulation

- **EPA Mercury and Air Toxics Standards Rule.** The U.S. Environmental Protection Agency's (EPA) Mercury and Air Toxics Standards rule (MATS) applies the Clean Air Act (CAA) maximum achievable control technology (MACT) requirement to new or modified sources of emissions of mercury and arsenic, acid gas, nickel, selenium and cyanide.[117] All coal steam units in PJM are compliant with the state and federal emissions limits established by MATS.
- **Air Quality Standards (NO_X and SO_2 Emissions).** The CAA requires each state to attain and maintain compliance with fine particulate matter (PM) and ozone national ambient air quality standards (NAAQS). The CAA also requires that each state prohibit emissions that significantly interfere with the ability of another state to meet NAAQS.[118]
- **National Emission Standards for Reciprocating Internal Combustion Engines.** The national emissions standards uniformly apply to all RICE.[119] All RICE are allowed to operate during emergencies, including declared Energy Emergency Alert Level 2 or five percent voltage/frequency deviations.[120]
- **Greenhouse Gas Emissions Rule.** On August 3, 2015, the EPA issued a final rule for regulating CO_2 from certain existing power generation facilities titled Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units (the Clean Power Plan).[121] On February 9, 2016, the U.S. Supreme Court issued a stay of the rule that will prevent its taking effect until judicial review

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

118 CAA § 110(a)(2)(D)(i)(I).

119 EPA, Memorandum, Peter Tsirigotis Guidance on Vacatur of RICE NESHAP and NSPS Provisions for Emergency Engines (April 15, 2016).

120 See 40 CFR §§ 60.4211(f)(2)(ii)–(iii), 60.4243(d)(2)(ii)–(iii), and 63.6640(f)(2)(ii)–(iii) (Declared Energy Emergency Alert Level 2 or 5 percent voltage/frequency deviations); 40 CFR §§ 60.4211(f)(1), 60.4243(d)(1), and 63.6640(f)(1) ("There is no time limit on the use of emergency stationary ICE in emergency situations."); 40 §§ CFR 60.4211(f)(3), 60.4243(d)(3), 63.6640(f)(3)–(4).

121 *Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units*, EPA-HQ-OAR-2013-0602, Final Rule mimeo (Aug. 3, 2015), also known as the "Clean Power Plan."

is completed.[122] On October 10, 2017, the EPA proposed to repeal the Clean Power Plan based a determination that the Plan exceeds the EPA's authority under Section 111 of the EPAs Act.[123]

- **Cooling Water Intakes.** An EPA rule implementing Section 316(b) of the Clean Water Act (CWA) requires that cooling water intake structures reflect the best technology available for minimizing adverse environmental impacts.[124]

State Environmental Regulation

- **Regional Greenhouse Gas Initiative (RGGI).** The Regional Greenhouse Gas Initiative (RGGI) is a CO_2 emissions cap and trade agreement among Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New York, Rhode Island, and Vermont that applies to power generation facilities. New Jersey is in the process of resuming participation.[125] Virginia is making preparations to join.[126] The auction price in the December 5, 2018, auction for the 2015/2018 compliance period was $5.33 per ton. The clearing price is equivalent to a price of $5.88 per metric tonne, the unit used in other carbon markets. The price increased by $0.83 per ton, 18.4 percent, from $4.50 per ton from September 9, 2018, to $5.33 per ton for December 5, 2018.

- **Carbon Price.** If the price of carbon were $50.00 per metric tonne, the short run marginal costs would increase by $25.04 per MWh for a new combustion turbine (CT) unit, $17.72 per MWh for a new combined cycle (CC) unit and $43.15 per MWh for a new coal plant (CP).

State Renewable Portfolio Standards

Many states in PJM have enacted legislation to require that a defined percentage of retail suppliers' load be served by renewable resources, for which definitions vary. These are typically known as renewable portfolio standards, or RPS. As of December 31, 2018, Delaware, Illinois, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, and Washington, DC had renewable portfolio standards. Virginia and Indiana had voluntary renewable portfolio standards. Kentucky and Tennessee did not have renewable portfolio standards.

Emissions Controls in PJM Markets

Environmental regulations affect decisions about emission control investments in existing units, investment in new units and decisions to retire units. As a result of environmental regulations and agreements to limit emissions, many PJM units burning fossil fuels have installed emission control technology. As of December 31, 2018, 93.6 percent of coal steam MW had some type of flue-gas desulfurization (FGD) technology to reduce SO_2 emissions, while 99.5 percent of coal steam MW had some type of particulate control, and 94.2 percent of fossil fuel fired capacity in PJM had NO_X emission control technology. All coal steam units in PJM are compliant with the state and federal emissions limits established by MATS.

Renewable Generation

Total wind and solar generation was 2.8 percent of total generation in PJM for 2018. Tier I generation was 4.5 percent of total generation in PJM and Tier II generation was 2.7 percent of total generation in PJM for 2018. Only Tier 1 generation is renewable.

Section 8 Recommendations

- The MMU recommends that renewable energy credit markets based on state renewable portfolio standards be brought into PJM markets as they are an increasingly important component of the wholesale energy market. (Priority: Medium. First reported 2010. Status: Not adopted.)
- The MMU recommends that the Commission reconsider its disclaimer of jurisdiction over RECs markets because, given market changes since that decision, it is clear that RECs materially affect jurisdictional rates. (Priority: High. New recommendation. Status: Not adopted.)
- The MMU recommends that states consider the development of a multistate framework for RECs markets, for potential agreement on carbon pricing

122 North Dakota v. EPA, et al., Order 15A793.

123 *See Repeal of Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units*, Proposed Rule, EPA Docket No. EPA-HQ-OAR-2017-0355, 82 Fed. Reg. 48035 (Oct. 16, 2017).

124 See EPA, *National Pollutant Discharge Elimination System—Final Regulations to Establish Requirements for Cooling Water Intake Structures at Existing Facilities and Amend Requirements at Phase I Facilities*, EPA-HQ-OW-2008-0667, 79 Fed. Reg. 48300 (Aug. 15, 2014).

125 Executive Order 7; see *Regional Greenhouse Gas Initiative*, State of New Jersey Department of Environmental Protection <http://www.state.nj.us/dep/aqes/rggi.html>.

126 See Regulation for Emissions Trading, 9 VAC 5-140. The Virginia Air Pollution Control Board is developing the regulation and considering public comments.

including the distribution of carbon revenues, and for coordination with PJM wholesale markets. (Priority: Medium. New recommendation. Status: Not adopted.)

- The MMU recommends that jurisdictions with a renewable portfolio standard make the price and quantity data on supply and demand more transparent. (Priority: Low. First reported Q2, 2018. Status: Not adopted.)

Section 8 Conclusion

Environmental requirements and renewable energy mandates at both the federal and state levels have a significant impact on the cost of energy and capacity in PJM markets. Renewable energy credit (REC) markets are markets related to the production and purchase of wholesale power, but FERC has determined that RECs are not regulated under the Federal Power Act unless the REC is sold as part of a transaction that also includes a wholesale sale of electric energy in a bundled transaction.[127] 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.

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

RECs markets are, as an economic fact, integrated with PJM markets including energy and capacity markets, but are not formally recognized as part of PJM markets. It would be preferable to have a single, transparent market for RECs operated by the PJM RTO that would meet the standards and requirements of all states in the PJM footprint including those with no RPS. This would provide better information for market participants about supply and demand and prices and contribute to a more efficient and competitive market and to better price formation. This could also facilitate entry by qualifying renewable resources by reducing the risks associated with lack of transparent market data. The MMU recommends that PJM states consider the development of a multistate framework for REC markets, for potential agreement on carbon pricing, and for coordination with PJM wholesale markets.

REC markets are not consistently or adequately transparent. Data on REC prices, clearing quantities and markets are not publicly available for all PJM states. The provision of more complete data would facilitate competition to provide energy from renewable sources.

The economic logic of RPS programs and the associated REC and SREC prices is not always clear. The price of carbon implied by REC prices ranges from $4.67 per tonne in Washington, D.C. to $35.41 per tonne in Pennsylvania. The price of carbon implied by SREC prices ranges from $17.71 per tonne in Pennsylvania to $812.07 per tonne in Washington, D.C. The effective prices for carbon compare to the 2018 average RGGI clearing price of $4.86 per tonne and to the social cost of carbon which is estimated in the range of $40 per tonne.[128] The impact on the cost of generation from a new combined cycle unit of an $800 per tonne carbon price would be $283.56 per MWh. The impact of a $40 per tonne carbon price would be $14.18 per MWh. This wide range of implied carbon prices is not consistent with an efficient, competitive, least cost approach to the reduction of emissions.

PJM markets provide a flexible mechanism for incorporating the costs of environmental controls and meeting environmental requirements in a cost effective manner. Costs for environmental controls are part of offers for capacity resources in the PJM Capacity Market. The costs of emissions credits are included in energy offers. PJM markets also provide a flexible mechanism

127 See 139 FERC ¶ 61,061 at PP 18, 22 (2012) ("[W]e conclude that unbundled REC transactions fall outside of the Commission's jurisdiction under sections 201, 205 and 206 of the FPA. We further conclude that bundled REC transactions fall within the Commission's jurisdiction under sections 201, 205 and 206 of the FPA,… [A]lthough a transaction may not directly involve the transmission or sale of electric energy, the transaction could still fall under the Commission's jurisdiction because it is 'in connection with' or 'affects' jurisdictional rates or charges.").

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

that incorporates renewable resources and the impacts of renewable energy credit markets, and ensures that renewable resources have access to a broad market. PJM markets provide efficient price signals that permit valuation of resources with very different characteristics when they provide the same product.

PJM markets could also provide a flexible mechanism to limit carbon output, for example by incorporating a consistent carbon price in unit offers which would be reflected in PJM's economic dispatch. If there is a social decision to limit carbon output, a consistent carbon price would be the most efficient way to implement that decision. The states in PJM could agree, if they decided it was in their interests, with the appropriate information, on a carbon price and on how to allocate the revenues from a carbon price that would make all states better off. The MMU continues to recommend that PJM provide modeling information to the states adequate to inform such a decision making process. A carbon price would also be an alternative to specific subsidies to individual nuclear power plants and to the current wide range of implied carbon prices embedded in RPS programs and instead provide a market signal to which any resource could respond. The imposition of specific and prescriptive environmental dispatch rules would, in contrast, pose a threat to economic dispatch and efficient markets and create very difficult market power monitoring and mitigation issues. The provision of subsidies to individual units creates a discriminatory regime that is not consistent with competition. The use of inconsistent implied carbon prices by state is also inconsistent with an efficient market and inconsistent with the least cost approach to meeting state environmental goals.

Overview: Section 9, Interchange Transactions

Interchange Transaction Activity

- **Aggregate Imports and Exports in the Real-Time Energy Market.** In 2018, PJM was a monthly net importer of energy in the Real-Time Energy Market in March and April, and a net exporter of energy in the remaining months.[129] In 2018, the real-time net interchange of -19,010.4 GWh was higher than the net interchange of -22,958.1 GWh in 2017.
- **Aggregate Imports and Exports in the Day-Ahead Energy Market.** In 2018, PJM was a monthly net importer of energy in the Day-Ahead Energy Market in March, April, May, June, July, August and November, and a net exporter of energy in the remaining months. In 2018, the total day-ahead net interchange of 2,977.4 GWh was higher than net interchange of -19,550.1 GWh in 2017.
- **Aggregate Imports and Exports in the Day-Ahead and the Real-Time Energy Market.** In 2018, gross imports in the Day-Ahead Energy Market were 290.3 percent of gross imports in the Real-Time Energy Market (184.9 percent in 2017). In 2018, gross exports in the Day-Ahead Energy Market were 126.1 percent of the gross exports in the Real-Time Energy Market (125.4 percent in 2017).
- **Interface Imports and Exports in the Real-Time Energy Market.** In 2018, there were net scheduled exports at 11 of PJM's 20 interfaces in the Real-Time Energy Market.[130]
- **Interface Pricing Point Imports and Exports in the Real-Time Energy Market.** In 2018, there were net scheduled exports at 12 of PJM's 18 interface pricing points eligible for real-time transactions in the Real-Time Energy Market.[131] [132]
- **Interface Imports and Exports in the Day-Ahead Energy Market.** In 2018, there were net scheduled exports at 12 of PJM's 20 interfaces in the Day-Ahead Energy Market.[133]
- **Interface Pricing Point Imports and Exports in the Day-Ahead Energy Market.** In 2018, there were net scheduled exports at nine of PJM's 19 interface pricing points eligible for day-ahead transactions in the Day-Ahead Energy Market.[134]
- **Up To Congestion Interface Pricing Point Imports and Exports in the Day-Ahead Energy Market.** In 2018, up to congestion transactions were net exports at four of PJM's 19 interface pricing points eligible for day-ahead transactions in the Day-Ahead Energy Market.[135]

129 Calculated values shown in Section 9, "Interchange Transactions," are based on unrounded, underlying data and may differ from calculations based on the rounded values in the tables.

130 In December 2018, PJM integrated OVEC, reducing the number of real-time interfaces to 19.

131 There is one interface pricing point eligible for day-ahead transaction scheduling only (NIPSCO).

132 In December 2018, PJM integrated OVEC, reducing the number of real-time interface pricing points to 17.

133 In December 2018, PJM integrated OVEC, reducing the number of day-ahead interfaces to 19.

134 In December 2018, PJM integrated OVEC, reducing the number of day-ahead interface pricing points to 18.

135 In December 2018, PJM integrated OVEC, reducing the number of day-ahead interface pricing points to 18.

- **Inadvertent Interchange.** In 2018, net scheduled interchange was 19,010 GWh and net actual interchange was 18,351 GWh, a difference of 659 GWh. In 2017, the difference was 189 GWh. This difference is inadvertent interchange.
- **Loop Flows.** In 2018, the Northern Indiana Public Service (NIPS) Interface had the largest loop flows of any interface with 3 GWh of net scheduled interchange and -8,681 GWh of net actual interchange, a difference of 8,684 GWh. In 2018, the SouthIMP interface pricing point had the largest loop flows of any interface pricing point with 10,316 GWh of net scheduled interchange and 29,635 GWh of net actual interchange, a difference of 19,319 GWh.

Interactions with Bordering Areas

PJM Interface Pricing with Organized Markets

- **PJM and MISO Interface Prices.** In 2018, the direction of the hourly flow was consistent with the real-time hourly price differences between the PJM/MISO Interface and the MISO/PJM Interface in 56.8 percent of the hours.
- **PJM and New York ISO Interface Prices.** In 2018, the direction of the hourly flow was consistent with the real-time hourly price differences between the PJM/NYIS Interface and the NYISO/PJM proxy bus in 52.5 percent of the hours.
- **Neptune Underwater Transmission Line to Long Island, New York.** In 2018, the hourly flow (PJM to NYISO) was consistent with the real-time hourly price differences between the PJM Neptune Interface and the NYISO Neptune bus in 60.3 percent of the hours.
- **Linden Variable Frequency Transformer (VFT) Facility.** In 2018, the hourly flow (PJM to NYISO) was consistent with the real-time hourly price differences between the PJM Linden Interface and the NYISO Linden bus in 58.9 percent of the hours.
- **Hudson DC Line.** In 2018, the hourly flow (PJM to NYISO) was consistent with the real-time hourly price differences between the PJM Hudson Interface and the NYISO Hudson bus in 56.7 percent of the hours.

Interchange Transaction Issues

- **PJM Transmission Loading Relief Procedures (TLRs).** PJM issued five TLRs of level 3a or higher in 2018, compared to six such TLRs issued in 2017.
- **Up To Congestion.** On February 20, 2018, FERC issued an order limiting the eligible bidding points for up to congestion transactions to hubs, residual metered load and interfaces.[136] As a result, market participants reduced up to congestion trading effective February 22, 2018. The average number of up to congestion bids submitted in the Day-Ahead Energy Market decreased by 53.4 percent, from 138,489 bids per day in 2017 to 64,574 bids per day in 2018. The average cleared volume of up to congestion bids submitted in the Day-Ahead Energy Market decreased by 49.5 percent, from 838,258 MWh per day in 2017, to 422,981 MWh per day in 2018.
- **45 Minute Schedule Duration Rule.** Effective May 19, 2014, PJM removed the 45 minute scheduling duration rule in response to FERC Order No. 764.[137] [138] PJM and the MMU issued a statement indicating ongoing concern about market participants' scheduling behavior, and a commitment to address any scheduling behavior that raises operational or market manipulation concerns.[139]

Section 9 Recommendations

- The MMU recommends that PJM implement rules to prevent sham scheduling. The MMU recommends that PJM apply after the fact market settlement adjustments to identified sham scheduling segments to ensure that market participants cannot benefit from sham scheduling. (Priority: High. First reported 2012. Status: Not adopted. Stakeholder process.)
- 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

136 162 FERC ¶ 61,139 (2018).
137 Order No. 764, 139 FERC ¶ 61,246 (2012), *order on reh'g*, Order No. 764-A, 141 FERC ¶ 61231 (2012).
138 *See* Letter Order, Docket No. ER14-381-000 (June 30, 2014).
139 *See* joint statement of PJM and the MMU re Interchange Scheduling issued July 29, 2014, at: <http://www.monitoringanalytics.com/reports/Market_Messages/Messages/PJM_IMM_Statement_on_Interchange_Scheduling_20140729.pdf>.

or sink of the transaction. (Priority: Medium. First reported 2013. Status: Not adopted.)

- The MMU recommends that PJM implement a validation method for submitted transactions that would require market participants to submit transactions on paths that reflect the expected actual power flow in order to reduce unscheduled loop flows. (Priority: Medium. First reported 2013. Status: Not adopted.)
- The MMU recommends that PJM end the practice of maintaining outdated definitions of interface pricing points, eliminate the NIPSCO, Southeast and Southwest interface pricing points from the 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. (Priority: Medium. First reported 2013. Status: Not adopted.)
- The MMU recommends that PJM eliminate the IMO interface pricing point, and assign the transactions that originate or sink in the IESO balancing authority to the MISO interface pricing point. (Priority: Medium. First reported 2013. Status: Not adopted.)
- The MMU recommends that PJM monitor, and adjust as necessary, the weights applied to the components of the interfaces to ensure that the interface prices reflect ongoing changes in system conditions. The MMU also recommends that PJM review the mappings of external balancing authorities to individual interface pricing points to reflect changes to the impact of the external power source on PJM tie lines as a result of system topology changes. The MMU recommends that this review occur at least annually. (Priority: Low. First reported 2009. Status: Not adopted.)
- The MMU recommends that, in order to permit a complete analysis of loop flow, FERC and NERC ensure that the identified data are made available to market monitors as well as other industry entities determined appropriate by FERC. (Priority: Medium. First reported 2003. Status: Not adopted.)
- The MMU recommends that PJM explore an interchange optimization solution with its neighboring balancing authorities that would remove the need for market participants to schedule physical transactions across seams. Such a solution would include an optimized, but limited, joint dispatch approach that uses supply curves and treats seams between balancing authorities as constraints, similar to other constraints within an LMP market. (Priority: Medium. First reported 2014. Status: Not adopted.)
- The MMU recommends that PJM permit unlimited spot market imports as well as unlimited nonfirm point-to-point willing to pay congestion imports and exports at all PJM interfaces in order to improve the efficiency of the market. (Priority: Medium. First reported 2012. Status: Not adopted.)
- The MMU recommends that PJM immediately provide the required 12-month notice to Duke Energy Progress (DEP) to unilaterally terminate the Joint Operating Agreement. (Priority: Low. First reported 2013. Status: Not adopted.)
- The MMU recommends that PJMSettlement 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. (Priority: Low. First reported 2015. Status: Not adopted.)
- The MMU recommends that the emergency interchange cap be replaced with a market based solution. (Priority: Low. First reported 2015. Status: Not adopted.)
- The MMU recommends that the submission deadline for real-time dispatchable transactions be modified from 1800 on the day prior, to three hours prior to the requested start time, and that the minimum duration be modified from one hour to 15 minutes. These changes would give PJM a more flexible product that could be used to meet load in the most economic manner. (Priority: Medium. First reported 2014. Status: Partially adopted, 2015.)

Section 9 Conclusion

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

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

Overview: Section 10, Ancillary Services

Primary Reserve

PJM's primary reserves are made up of resources, both synchronized and nonsynchronized, that can provide energy within 10 minutes. Primary reserve is PJM's implementation of the NERC 15-minute contingency reserve requirement.[140]

On April 1, 2018, PJM implemented five minute settlements. PJM determines the primary reserve requirement based on the most severe single contingency every five minutes. The market solution calculates the available tier 1 synchronized reserve every five minutes. In every five minute interval, the required synchronized reserve and nonsynchronized reserve are calculated and dispatched, and there are associated clearing prices (SRMCP and NSRMCP). Scheduled resources are credited based on their five minute assignment and clearing price.

Market Structure

- **Supply.** Primary reserve is satisfied by both synchronized reserve (generation or demand response currently synchronized to the grid and available within 10 minutes), and nonsynchronized reserve (generation currently off-line but available to start and provide energy within 10 minutes).
- **Demand.** The PJM primary reserve requirement is 150 percent of the most severe single contingency. In 2018, the average primary reserve requirement was 2,267.8 MW in the RTO Zone and 2,247.3 MW in the MAD Subzone.

Tier 1 Synchronized Reserve

Synchronized reserve is provided by generators or demand response resources synchronized to the grid and capable of increasing output or decreasing load within 10 minutes. Synchronized reserve consists of tier 1 and tier 2 synchronized reserves.

Tier 1 synchronized reserve is the capability of online resources following economic dispatch to ramp up in 10 minutes from their current output in response to a synchronized reserve event. There is no formal market for tier 1 synchronized reserve.

- **Supply.** No offers are made for tier 1 synchronized reserves. The market solution estimates tier 1 synchronized reserve as available 10 minute ramp from the energy dispatch. In 2018, there was an average hourly supply of 1,711.9 MW of tier 1 available in the RTO Zone. In 2018, there was an average hourly supply of 771.9 MW of tier 1 synchronized reserve available within the MAD Subzone and an additional 588.2 MW of tier 1 available to the MAD Subzone from the RTO Zone.
- **Demand.** The synchronized reserve requirement is calculated for each five minute interval as the most severe single contingency within both the RTO Zone and the MAD Subzone. The requirement can be met with tier 1 or tier 2 synchronized reserves.
- **Tier 1 Synchronized Reserve Event Response.** Tier 1 synchronized reserve is paid when a synchronized reserve event occurs and it responds. When a synchronized reserve event is called, all tier 1 response is paid the average of five minute LMPs

140 See PJM. "Manual 10: Pre-Scheduling Operations," § 3.1.1 Day-ahead Scheduling (Operating Reserve, Rev. 37 (Dec. 10, 2018).

during the event plus $50 per MWh.[141] This is the Synchronized Energy Premium Price.

Of the Degree of Generator Performance (DGP) adjusted tier 1 synchronized reserve MW estimated at market clearing, 63.3 percent actually responded during the seven synchronized reserve events of 10 minutes or longer in 2018.

- **Issues.** The competitive offer for tier 1 synchronized reserves is zero, as there is no incremental cost associated with the ability to ramp up from the current economic dispatch point and the appropriate payment for responding to an event is the five-minute LMP plus $50 per MWh. The tariff requires payment of the tier 2 synchronized reserve market clearing price to tier 1 resources whenever the nonsynchronized reserve market clearing price rises above zero. This requirement is unnecessary and inconsistent with efficient markets. This change had a significant impact on the cost of tier 1 synchronized reserves, resulting in a windfall payment of $89,719,045 to tier 1 resources in 2014, $34,397,441 in 2015, $4,948,084 in 2016, $2,197,514 in 2017, and $4,732,025 in 2018.

Tier 2 Synchronized Reserve Market

Tier 2 synchronized reserve is part of primary reserve and is comprised of resources that are synchronized to the grid, that may incur costs to be synchronized, that have an obligation to respond, that have penalties for failure to respond, and that must be dispatched in order to satisfy the synchronized reserve requirement.

When the synchronized reserve requirement cannot be met with tier 1 synchronized reserve, PJM uses a market to satisfy the balance of the requirement with tier 2 synchronized reserve. The Tier 2 Synchronized Reserve Market includes the PJM RTO Reserve Zone and a subzone, the Mid-Atlantic Dominion Reserve Subzone (MAD).

Market Structure

- **Supply.** In 2018, the supply of offered and eligible tier 2 synchronized reserve was 26,086.3 MW in the RTO Zone of which 7,230.9 MW was located in the MAD Subzone. 2,821.0 MW of DSR was available in the RTO Zone.

- **Demand.** The average hourly synchronized reserve requirement was 1,577.8 MW in the RTO Reserve Zone and 1,564.3 MW for the Mid-Atlantic Dominion Reserve Subzone. The hourly average cleared tier 2 synchronized reserve was 352.4 MW in the MAD Subzone and 598.4 MW in the RTO.

- **Market Concentration.** Both the Mid-Atlantic Dominion Subzone Tier 2 Synchronized Reserve Market and the RTO Synchronized Reserve Zone Market were characterized by structural market power in 2018.

  In 2018 10.2 percent of hours would have failed a three pivotal supplier test. In 2018, the average HHI for tier 2 synchronized reserve in the RTO Zone was 5007 which is classified as highly concentrated.

Market Conduct

- **Offers.** There is a must offer requirement for tier 2 synchronized reserve. All nonemergency generation capacity resources are required to submit a daily offer for tier 2 synchronized reserve, unless the unit type is exempt. Tier 2 synchronized reserve offers from generating units are subject to an offer cap of marginal cost plus $7.50 per MW, plus opportunity cost which is calculated by PJM. PJM automatically enters an offer of $0 for tier 2 synchronized reserve when an offer is not entered by the owner.

Market Performance

- **Price.** The weighted average price for tier 2 synchronized reserve for all cleared hours/intervals in the Mid-Atlantic Dominion (MAD) Subzone was $5.39 per MW in 2018, an increase of $2.11 from 2017.

  The weighted average price for tier 2 synchronized reserve for all cleared hours/intervals in the RTO Synchronized Reserve Zone was $6.15 per MW in 2018, an increase of $2.37 from 2017.

Nonsynchronized Reserve Market

Nonsynchronized reserve is part of primary reserve and includes the RTO Reserve Zone and the Mid-Atlantic Dominion Reserve Subzone (MAD). Nonsynchronized reserve is comprised of nonemergency energy resources not currently synchronized to the grid that can provide

141 See PJM. "Manual 11: Energy & Ancillary Services Market Operations,"§ 4.2.10 Settlements, Rev. 104 (Feb. 7, 2019).

energy within 10 minutes. Nonsynchronized reserve is available to fill the primary reserve requirement above the synchronized reserve requirement. Generation owners do not submit supply offers for nonsynchronized reserve. PJM defines the demand curve for nonsynchronized reserve and PJM defines the supply curve based on nonemergency generation resources that are available to provide energy and can start in 10 minutes or less (based on offer parameters), and on the resource opportunity costs calculated by PJM.

Market Structure

- **Supply.** In 2018, the average hourly supply of eligible nonsynchronized reserve was 3,683.2 MW in the RTO Zone.
- **Demand.** Demand for nonsynchronized reserve equals the primary reserve requirement minus the tier 1 synchronized reserve estimate and minus the scheduled tier 2 synchronized reserve.[142] In the RTO Zone, the market scheduled an hourly average of 1,968.8 MW of nonsynchronized reserve in 2018.
- **Market Concentration.** The MMU calculates that the three pivotal supplier test would have failed in 44.8 percent of hours. In 2018, the weighted average HHI for cleared nonsynchronized reserve in the RTO Zone was 4443, which is highly concentrated.

Market Conduct

- **Offers.** Generation owners do not submit supply offers. Nonemergency generation resources that are available to provide energy and can start in 10 minutes or less are considered available for nonsynchronized reserves by the market solution software. PJM calculates the associated offer prices based on PJM calculations of resource specific opportunity costs.

Market Performance

- **Price.** The nonsynchronized reserve price is determined by the opportunity cost of the marginal nonsynchronized reserve unit. The nonsynchronized reserve weighted average price for all hours in the RTO Reserve Zone was $0.29 per MW in 2018. The price cleared above $0.00 in 1.0 percent of hours.

Secondary Reserve

There is no NERC standard for secondary reserve. PJM defines secondary reserve as reserves (online or offline available for dispatch) that can be converted to energy in 30 minutes. PJM defines a secondary reserve requirement but does not have a goal to maintain this reserve requirement in real time.

PJM maintains a day-ahead, offer-based market for 30 minute day-ahead secondary reserve. The Day-Ahead Scheduling Reserve Market (DASR) has no performance obligations except that a unit which clears the DASR market may not be on an outage in real time.[143] If DASR units are on an outage in real time or cleared DASR MW are not available, the DASR payment is not made.

Market Structure

- **Supply.** The DASR Market is a must offer market. Any resources that do not make an offer have their offer set to $0.00 per MW. DASR is calculated by the day-ahead market solution as the lesser of the 30 minute energy ramp rate or the economic maximum MW minus the day-ahead dispatch point for all online units. In 2018, the average available hourly DASR was 39,595.6 MW.
- **Demand.** The DASR requirement for 2018 is 5.28 percent of peak load forecast, down from 5.52 percent in 2017. The average DASR MW purchased in 2018 was 5,690.1 MW per hour, compared to 4,477.3 MW per hour in 2017.
- **Concentration.** In 2018, the DASR Market would have failed the three pivotal supplier test in 9.8 percent of hours.

Market Conduct

- **Withholding.** Economic withholding remains an issue in the DASR Market. The direct marginal cost of providing DASR is zero. PJM calculates the opportunity cost for each resource. All offers by resource owners greater than zero constitute economic withholding. In 2018, a daily average of 38.8 percent of units offered above $0.00. A daily average of 15.8 percent of units offered above $5.
- **DR.** Demand resources are eligible to participate in the DASR Market. Some demand resources have

142 See PJM. "Manual 11: Energy & Ancillary Services Market Operations," § $b.2.2 Non-Synchronized Reserve Zones and Levels, Rev. 104 (February 7, 2019). "Because Synchronized Reserve may be utilized to meet the Primary Reserve requirement, there is no explicit requirement for non-synchronized reserves."

143 See PJM, "Manual 11: Energy & Ancillary Services Market Operations," § 11.2.7 Day-Ahead Scheduling Reserve Performance, Rev. 104 (February 7, 2019),

entered offers for DASR. No demand resources cleared the DASR market in 2018.

Market Performance

- **Price.** In 2018, the weighted average DASR price for all hours when the DASRMCP was above $0.00 was $3.49.

Regulation Market

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

Market Structure

- **Supply.** In 2018, the average hourly eligible supply of regulation for nonramp hours was 1,125.5 performance adjusted MW (876.2 effective MW). This was a decrease of 10.6 performance adjusted MW (a decrease of 7.1 effective MW) from 2017, when the average hourly eligible supply of regulation was 1,136.1 performance adjusted MW (869.0 effective MW). In 2018, the average hourly eligible supply of regulation for ramp hours was 1,438.3 performance adjusted MW (1,204.1 effective MW). This was an increase of 11.1 performance adjusted MW (an increase of 20.7 effective MW) from 2017, when the average hourly eligible supply of regulation was 1,427.2 performance adjusted MW (1,183.4 effective MW).
- **Demand.** Prior to January 9, 2017, the hourly regulation demand was set to 525.0 effective MW for nonramp hours and 700.0 effective MW for ramp hours. Starting January 9, 2017, the hourly regulation demand was set to 525.0 effective MW for nonramp hours and 800.0 effective MW for ramp hours.
- **Supply and Demand.** The nonramp regulation requirement of 525.0 effective MW was provided by a combination of RegA and RegD resources equal to 483.0 hourly average performance adjusted actual MW in 2018. This is a decrease of 5.1 performance adjusted actual MW from 2017, when the average hourly total regulation cleared performance adjusted actual MW for nonramp hours were 488.1 performance adjusted actual MW. The ramp regulation requirement of 800.0 effective MW was provided by a combination of RegA and RegD resources equal to 749.3 hourly average performance adjusted actual MW in 2018. This is an increase of 29.1 performance adjusted actual MW from 2017, where the average hourly regulation cleared MW for ramp hours were 720.2 performance adjusted actual MW.

  The ratio of the average hourly eligible supply of regulation to average hourly regulation demand (performance adjusted cleared MW) for ramp hours was 1.92 in 2018. This is a decrease of 3.22 percent from 2017, when the ratio was 1.98. The ratio of the average hourly eligible supply of regulation to average hourly regulation demand (performance adjusted cleared MW) for nonramp hours was 2.33 in 2018, unchanged from the ratio in 2017.
- **Market Concentration.** In 2018, the three pivotal supplier test was failed in 81.7 percent of hours. In 2018, the effective MW weighted average HHI of RegA resources was 2419 which is highly concentrated and the weighted average HHI of RegD resources was 1546 which is also highly concentrated.[144] The weighted average HHI of all resources was 1125, which is moderately concentrated.

144 HHI results are based on market shares of effective MW, defined as regulation capability MW adjusted by performance score and resource specific benefit factor, consistent with the way the regulation market is cleared.

Market Conduct

- **Offers.** Daily regulation offer prices are submitted for each unit by the unit owner. Owners are required to submit a cost-based offer and may submit a price-based offer. Offers include both a capability offer and a performance offer. Owners must specify which signal type the unit will be following, RegA or RegD.[145] In 2018, there were 227 resources following the RegA signal and 69 resources following the RegD signal.

Market Performance

- **Price and Cost.** The weighted average clearing price for regulation was $25.33 per MW of regulation in 2018. This is an increase of $8.55 per MW, or 50.9 percent, from the weighted average clearing price of $16.78 per MW in 2017. The weighted average cost of regulation in 2018 was $31.94 per MW of regulation. This is an increase of $8.90 per MW, or 38.6 percent, from the weighted average cost of $23.04 per MW in 2017.

- **Prices.** RegD resources continue to be incorrectly compensated relative to RegA resources due to an inconsistent application of the marginal benefit factor in the optimization, assignment and settlement processes. If the Regulation Market were functioning efficiently, RegD and RegA resources would be paid the same price per effective MW. RegA resources are paid on the basis of dollars per effective MW of RegA. RegD resources are not paid in terms of dollars per effective MW of RegA because the marginal benefit factor is not used in settlements. When the marginal benefit factor is above 1.0, RegD resources are generally (depending on the mileage ratio) underpaid on a per effective MW basis. When the MBF is less than one, RegD resources are generally overpaid on a per effective MW basis.

- **Marginal Benefit Factor Function.** The marginal benefit factor (MBF) is intended to measure the operational substitutability of RegD resources for RegA resources. The marginal benefit factor function is incorrectly defined and applied in the PJM market clearing. Correctly defined, the MBF function represents the Marginal Rate of Technical Substitution (MRTS) between RegA and RegD. Correctly implemented, the MBF would be consistently applied in the Regulation Market clearing and settlement. The current incorrect and inconsistent implementation of the MBF function has resulted in the PJM Regulation Market over procuring RegD relative to RegA in most hours and in a consistently inefficient market signal to participants regarding the value of RegD to the market in every hour. This over procurement of RegD can also degrade the ability of PJM to control ACE.

- **Changes to the Regulation Market.** The MMU and PJM developed a joint proposal to address the significant flaws in the regulation market design which was approved by the PJM Members Committee on July 27, 2017, and filed with FERC on October 17, 2017. The proposal addresses issues with the inconsistent application of the marginal benefit factor throughout the optimization and settlement process in the PJM Regulation Market. On March 30, 2018, this joint proposal was rejected by FERC.[146] The MMU and PJM have filed requests for rehearing.[147]

Black Start Service

Black start service is required for the reliable restoration of the grid following a blackout. Black start service is the ability of a generating unit to start without an outside electrical supply, or is the demonstrated ability of a generating unit to automatically remain operating at reduced levels when disconnected from the grid (automatic load rejection or ALR).[148]

In 2018, total black start charges were $64.7 million, including $64.4 million in revenue requirement charges and $0.303 million in operating reserve charges. Black start revenue requirements consist of fixed black start service costs, variable black start service costs, training costs, fuel storage costs, and an incentive factor. Black start operating reserve charges are paid to units scheduled in the Day-Ahead Energy Market or committed in real time to provide black start service under the ALR option or for black start testing. Black start zonal charges in 2018 ranged from $0.07 per MW-day in the DLCO Zone

145 See the *2018 State of the Market Report for PJM*, Vol. 2, Appendix F "Ancillary Services Markets."

146 162 FERC ¶ 61,295.

147 FERC Docket No. ER18-87-002.

148 OATT Schedule 1 § 1.3BB.

(total charges were $72,167) to $4.26 per MW-day in the PENELEC Zone (total charges were $4,496,206).

Reactive

Reactive service, reactive supply and voltage control are provided by generation and other sources of reactive power (measured in MVAr). Reactive power helps maintain appropriate voltage levels on the transmission system and is essential to the flow of real power (measured in MW).

Reactive capability revenue requirements are based on FERC approved filings that permit recovery based on a cost of service approach.[149] Reactive service charges are paid to units that operate in real time outside of their normal range at the direction of PJM for the purpose of providing reactive service. Reactive service charges are paid for scheduling in the Day-Ahead Energy Market and committing units in real time that provide reactive service. In 2018, total reactive charges were $342.0 million, a 3.1 percent increase from $331.7 million in 2017. Reactive capability revenue requirement charges increased from $311.3 million in 2017 to $328.8 million in 2018 and reactive service charges decreased from $20.4 million in 2017 to $13.1 million in 2018. Total reactive service charges in 2018 ranged from $0 in the RECO Zone, which has no generating units, to $50.8 million in the ComEd Zone.

Frequency Response

On February 15, 2018, the Commission issued Order No. 842, which modified the pro forma large and small generator interconnection agreements and procedures to require newly interconnecting generating facilities, both synchronous and non-synchronous, to include equipment for primary frequency response capability as a condition to receive interconnection service.[150] PJM filed revisions in compliance with Order No. 842 that substantively incorporated the pro forma agreements into its market rules.[151]

149 OATT Schedule 2.
150 See 157 FERC ¶ 61,122 (2016).
151 See 164 FERC ¶ 61,224 (2018).

Section 10 Recommendations

- The MMU recommends that the Regulation Market be modified to incorporate a consistent application of the marginal benefit factor (MBF) throughout the optimization, assignment and settlement process. The MBF should be defined as the Marginal Rate of Technical Substitution (MRTS) between RegA and RegD. (Priority: High. First reported 2012. Status: Not adopted. FERC rejected, pending rehearing request before FERC.[152])
- The MMU recommends that the lost opportunity cost in the ancillary services markets be calculated using the schedule on which the unit was scheduled to run in the energy market. (Priority: High. First reported 2010. Status: Not adopted.[153] FERC rejected, pending rehearing request before FERC.[154])
- The MMU recommends that the lost opportunity cost calculation used in the Regulation Market be based on the resource's dispatched energy offer schedule, not the lower of its price or cost offer schedule. (Priority: Medium. First reported 2010. Status: Not adopted. FERC rejected, pending rehearing request before FERC.[155])
- The MMU recommends that, to prevent gaming, there be a penalty enforced in the Regulation Market as a reduction in performance score and/or a forfeiture of revenues when resource owners elect to deassign assigned regulation resources within the hour. (Priority: Medium. First reported 2016. Status: Not adopted. FERC rejected, pending rehearing request before FERC.[156])
- The MMU recommends enhanced documentation of the implementation of the Regulation Market design. (Priority: Medium. First reported 2010. Status: Not adopted. FERC rejected, pending rehearing request before FERC.[157])
- The MMU recommends that all data necessary to perform the Regulation Market three pivotal supplier test be saved so that the test can be

152 FERC Docket No. ER18-87.
153 This recommendation was adopted by PJM for the Energy Market. Lost opportunity costs in the Energy Market are calculated using the schedule on which the unit was scheduled to run. In the Regulation Market, this recommendation has not been adopted, as the LOC continues to be calculated based on the lower of price or cost in the energy market offer.
154 FERC Docket No. ER18-87.
155 *Id.*
156 *Id.*
157 *Id.*

replicated. (Priority: Medium. First reported 2016. Status: Adopted, 2018.)

- The MMU recommends that PJM be required to save data elements necessary for verifying the performance of the Regulation Market. (Priority: Medium. First reported 2010. Status: Not adopted.)
- The MMU recommends that the $7.50 margin be eliminated from the definition of the cost of tier 2 synchronized reserve because it is a markup and not a cost. (Priority: Medium. First reported Q3, 2018. Status: Not adopted.)
- 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. (Priority: High. First reported 2013. Status: Not adopted.)
- The MMU recommends that the tier 2 synchronized reserve must offer requirement be enforced on a daily and hourly basis. The MMU recommends that PJM define a set of acceptable reasons why a unit can be made unavailable daily or hourly and require unit owners to select a reason in Markets Gateway whenever making a unit unavailable either daily or hourly or setting the offer MW to 0 MW. (Priority: Medium. First reported 2013. Status: Partially adopted.)
- 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. (Priority: Medium. First reported 2012. Status: Not adopted.)
- 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. (Priority: Medium. First reported Q3, 2018. Status: Not adopted.)
- The MMU recommends that aggregation not be permitted to offset unit specific penalties for failure to respond to a synchronized reserve event. (Priority: Medium. First reported Q3, 2018. Status: Not adopted.)
- The MMU recommends that PJM eliminate the use of Degree of Generator Performance (DGP) in the synchronized reserve market solution and improve the actual tier 1 estimate. If PJM continues to use DGP, DGP should be documented in PJM's manuals. (Priority: Medium. New recommendation. Status: Not adopted.)
- The MMU recommends that a reason code be attached to every hour in which PJM market operations adds additional DASR MW. (Priority: Medium. First reported 2015. Status: Not adopted.)
- The MMU recommends that PJM modify the DASR Market to ensure that all resources cleared incur a real-time performance obligation. (Priority: Low. First reported 2013. Status: Not adopted.)
- The MMU recommends that offers in the DASR Market be based on opportunity cost only in order to eliminate market power. (Priority: Low. First reported 2009. Modified, 2018. Status: Not adopted.)
- The MMU recommends that separate cost of service payments for reactive capability be eliminated and the cost of reactive capability be recovered in the capacity market. (Priority: Medium. First reported 2016. Status: Not adopted.)
- The MMU recommends that payments for reactive capability, if continued, be based on the 0.90 power factor that PJM has determined is necessary. (Priority: Medium. First reported Q3, 2018. Status: Not adopted.)
- 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. (Priority: Medium. New recommendation. Status: Not adopted.)
- The MMU recommends 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

the MTSL will be calculated for black start units sharing oil tanks. (Priority: Medium. First reported 2017. Status: Not adopted.)

- 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. (Priority: Low. First reported 2017. Status: Not adopted.)

Section 10 Conclusion

The current PJM regulation market design that incorporates two signals using two resource types was a result of FERC Order No. 755 and subsequent orders.[158]

The design of the PJM Regulation Market is significantly flawed. The market design does not correctly incorporate the marginal rate of technical substitution (MRTS) in market clearing and settlement. The market design uses the marginal benefit factor (MBF) to incorrectly represent the MRTS and uses a mileage ratio instead of the MBF in settlement. This failure to correctly and consistently incorporate the MRTS into the regulation market design has resulted in both underpayment and overpayment of RegD resources and in the over procurement of RegD resources in all hours. The market results continue to include the incorrect definition of opportunity cost. These issues are the basis for the MMU's conclusion that the regulation market design is flawed.

To address these flaws, the MMU and PJM developed a joint proposal which was approved by the PJM Members Committee on July 27, 2017, and filed with FERC on October 17, 2017.[159] The PJM/MMU joint proposal addresses issues with the inconsistent application of the marginal benefit factor throughout the optimization and settlement process in the PJM Regulation Market. FERC rejected the joint proposal on March 30, 2018, as being noncompliant with Order No. 755.[160] The MMU and PJM have separately filed requests for rehearing.[161]

158 Order No. 755, 137 FERC ¶ 61,064 at PP 197–200 (2011).
159 18 CFR § 385,211 (2017)
160 162 FERC ¶ 61,295 (2018).
161 The MMU filed its request for rehearing on April 27, 2018, and PJM filed its request for rehearing on April 30, 2018.

The structure of the Tier 2 Synchronized Reserve Market has been evaluated and the MMU has concluded that these markets are not structurally competitive as they are characterized by high levels of supplier concentration and inelastic demand. As a result, these markets are operated with market clearing prices and with offers based on the marginal cost of producing the product plus a margin. As a result of these requirements, the conduct of market participants within these market structures has been consistent with competition, and the market performance results have been competitive. However, the $7.50 margin is not a cost. The margin is effectively a rule-based form of market power and is therefore not consistent with a competitive outcome. The $7.50 margin should be eliminated. Participant performance has not been adequate. Compliance with calls to respond to actual synchronized reserve events remains less than 100 percent. For the spinning events 10 minutes or longer in 2016, the average tier 2 synchronized reserve response was 85.5 percent of all scheduled MW. For the six spinning events 10 minutes or longer in 2017, the response was 87.6 percent of scheduled tier 2 MW. For the seven spinning events longer than 10 minutes in 2018, the response was 74.2 percent of scheduled tier 2 MW. Actual participant performance implies that the penalty structure is not adequate to incent performance.

The rule that requires payment of the tier 2 synchronized reserve price to tier 1 synchronized reserve resources when the nonsynchronized reserve price is greater than zero, is inefficient and results in a substantial windfall payment to the holders of tier 1 synchronized reserve resources. Tier 1 resources have no obligation to perform and pay no penalties if they do not perform, and tier 1 resources do not incur any costs when they are part of the tier 1 estimate in the market solution. Tier 1 resources are already paid for their response if they do respond. Tier 1 resources require no additional payment. If tier 1 resources wish to be paid as tier 2 resources, the rules provide the opportunity to make competitive offers in the tier 2 market and take on the associated obligations. Overpayment of tier 1 resources based on this rule added $89.7 million to the cost of primary reserve in 2014, $34.1 million in 2015, $4.9 million in 2016, $2.2 million in 2017, and $4.7 million in 2018.

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

The MMU concludes that the regulation market results were competitive, although the market design is flawed. The MMU concludes that the synchronized reserve market results were competitive, although the $7.50 margin should be removed. The MMU concludes that the DASR market results were competitive, although offers above the competitive level continue to affect prices.

Overview: Section 11, Congestion and Marginal Losses

Congestion Cost

- **Total Congestion.** Total congestion costs increased by $612.3 million or 87.8 percent, from $697.6 million in 2017 to $1,309.9 million in 2018.
- **Day-Ahead Congestion.** Day-ahead congestion costs increased by $645.9 million or 88.1 percent, from $733.1 million in 2017 to $1,378.9 million in 2018.
- **Balancing Congestion.** Negative balancing congestion costs increased by $33.6 million or 94.6 percent, from -$35.5 million in 2017 to -$69.0 million in 2018. Negative balancing explicit costs increased by $8.1 million or 77.8 percent, from -$10.4 million in 2017 to -$18.5 million in 2018.
- **Real-Time Congestion.** Real-time congestion costs increased by $667.6 million or 81.7 percent, from $817.5 million in 2017 to $1,485.1 million in 2018.
- **Monthly Congestion.** Monthly total congestion costs in 2018 ranged from $45.2 million in February to $535.9 million in January.
- **Geographic Differences in CLMP.** Differences in CLMP among eastern, southern and western control zones in PJM were primarily a result of congestion on the AEP - DOM Interface, the Cloverdale Transformer, the Tanners Creek - Miami Fort Flowgate, the Graceton - Safe Harbor Line, and the 5004/5005 Interface.
- **Congestion Frequency.** Congestion frequency continued to be significantly higher in the Day-Ahead Energy Market than in the Real-Time Energy Market in 2018. The number of congestion event hours in the Day-Ahead Energy Market was about six times the number of congestion event hours in the Real-Time Energy Market.

  But day-ahead congestion frequency decreased by 55.9 percent from 300,923 congestion event hours in 2017 to 132,598 congestion event hours in 2018 as a result of a significant decrease in up to congestion transaction (UTC) activities in response to the February 20, 2018, FERC order that limited UTC trading, effective February 22, 2018, to hubs, residual metered load, and interfaces.[162]

  Real-time congestion frequency increased by 2.3 percent from 22,393 congestion event hours in 2017 to 22,910 congestion event hours in 2018.
- **Congested Facilities.** Day-ahead, congestion event hours decreased on all types of facilities as a result of a significant decrease in UTC activities caused by the February 20, 2018, FERC order.

  The AEP - DOM Interface was the largest contributor to congestion costs in 2018. With $121.0 million in total congestion costs, it accounted for 9.2 percent of the total PJM congestion costs in 2018.
- **CT Pricing Logic and Closed Loop Interface Related Congestion.** CT pricing logic and closed loop interfaces caused -$1.3 million of day-ahead congestion in 2018 and -$10.2 million of balancing congestion in 2018.
- **Zonal Congestion.** Using the constraint based measure, AEP had the largest zonal congestion costs among all control zones in 2018. AEP had $223.8 million in zonal congestion costs, comprised of $234.9 million in zonal day-ahead congestion costs and -$11.1 million in zonal balancing congestion costs. The AEP - DOM Interface, the Capitol Hill – Chemical Line, the Cloverdale Transformer, the Tanners Creek - Miami Fort Flowgate, and the Graceton - Safe Harbor Line contributed $71.4 million, or 31.9 percent of the local AEP control zone congestion costs.

162 162 FERC ¶ 61,139.

Marginal Loss Cost

- **Total Marginal Loss Costs.** Total marginal loss costs increased by $269.3 million or 39.0 percent, from $690.8 million in 2017 to $960.1 million in 2018. The loss MWh in PJM increased by 700.3 GWh or 4.7 percent, from 14,920 GWh in 2017 to 15,620 GWh in 2018. The loss component of real-time LMP in 2018 was $0.02, compared to $0.01 in 2017.
- **Monthly Total Marginal Loss Costs.** Monthly total marginal loss costs in 2018 ranged from $49.5 million in February to $222.8 million in January.
- **Day-Ahead Marginal Loss Costs.** Day-ahead marginal loss costs increased by $227.3 million or 29.5 percent, from $769.9 million in 2017 to $997.2 million in 2018.
- **Balancing Marginal Loss Costs.** Negative balancing marginal loss costs decreased by $42.0 million or 53.1 percent, from -$79.1 million in 2017 to -$37.1 million in 2018.
- **Total Marginal Loss Surplus.** The total marginal loss surplus increased in 2018 by $105.6 million or 49.2 percent, from $214.6 million in 2017, to $320.2 million in 2018.

Energy Cost

- **Total Energy Costs.** Total energy costs decreased by $161.5 million or 34.0 percent, from -$475.2 million in 2017 to -$636.7 million in 2018.
- **Day-Ahead Energy Costs.** Day-ahead energy costs decreased by $62.5 million or 9.6 percent, from -$648.5 million in 2017 to -$711.0 million in 2018.
- **Balancing Energy Costs.** Balancing energy costs decreased by $96.5 million or 58.1 percent, from $166.2 million in 2017 to $69.7 million in 2018.
- **Monthly Total Energy Costs.** Monthly total energy costs in 2018 ranged from -$150.9 million in January to -$33.6 million in February.

Section 11 Conclusion

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

Total congestion in 2018 increased significantly from 2017. The increase was a result of an increase in day-ahead congestion in January 2018 which was a result of high gas costs and associated LMPs in the early part of January 2018 and the use of high price oil fired units to control for contingencies caused by outages related to transmission upgrades in Virginia in May 2018.

Balancing explicit congestion decreased by $8.1 million or 77.8 percent, from -$10.4 million in 2017 to -$18.5 million in 2018. The decrease in balancing explicit congestion costs was the result of the decrease in balancing explicit costs incurred by up to congestion transactions (UTCs) in May and June of 2018. The balancing congestion costs were -$16.0 million and -$19.9 million in May and June. The large negative balancing congestion cost was caused in large part by UTCs profiting from day-ahead and real-time market modeling differences, including a number of constraints that were modeled in the real-time market but not modeled in the day-ahead market.

The monthly total congestion costs ranged from $45.2 million in February to $535.9 million in January, 2018.

The impact of UTCs on the frequency of day-ahead congestion was illustrated by the significant reduction in day-ahead congestion event hours following the decrease in up to congestion (UTC) transaction activities that resulted from the February 20, 2018, FERC order that limited UTC trading to hubs, residual metered load, and interfaces.

The current ARR/FTR design does not serve as an efficient way to ensure that load receives all the congestion revenues and has the ability to receive the auction revenues associated with rights to all the potential congestion revenues. Total ARR and self scheduled FTR revenue offset only 65.3, 90.3, 100.0, 50.0 and, if surplus through December 2018 were distributed, 74.2 percent of total congestion costs including congestion in the Day-Ahead Energy Market and the balancing energy market for the 2014/2015, 2015/2016, 2016/2017, 2017/2018 and the first seven months of 2018/2019 planning periods.

Overview: Section 12, Planning

Generation Interconnection Planning

Existing Generation Mix

- As of December 31, 2018, PJM had a total installed capacity of 199,489.0 MW, of which 57,891.9 MW (29.0 percent) are coal fired steam units, 46,207.1 MW (23.2 percent) are combined cycle units and 34,257.6 MW (17.2 percent) are nuclear units. This measure of installed capacity differs from capacity market installed capacity because it includes energy only units, excludes all external units, and uses nameplate values for solar and wind resources.
- The AEP Zone has the most total installed capacity of any PJM zone. Of the 199,489.0 MW of PJM total installed capacity, 31,643.0 MW (15.9 percent) are in the AEP Zone, of which 14,727.8 MW (46.5 percent) are coal fired steam units, 6,990.0 MW (22.1 percent) are combined cycle units and 2,071.0 MW (6.5 percent) are nuclear units.
- Pennsylvania has the most total installed capacity of any PJM state. Of the 199,489.0 MW of installed capacity, 44,753.1 MW (22.4 percent) are in Pennsylvania, of which 9,467.7 MW (21.2 percent) are coal fired steam units, 13,656.5 MW (30.5 percent) are combined cycle units and 9,648.8 MW (21.6 percent) are nuclear units.
- Of the 199,489.0 MW of installed capacity, 76,587.5 MW (38.4 percent) are from units older than 40 years, of which 41,426.7 MW (54.1 percent) are coal fired steam units, 16,044.9 MW (20.9 percent) are nuclear units, and 532.0 MW (0.7 percent) are combined cycle units.

Generation Retirements[163]

- There are 44,684.1 MW of generation that have been, or are planned to be, retired between 2011 and 2022, of which 31,621.4 MW (70.8 percent) are coal fired steam units. Coal unit retirements are primarily a result of the inability of coal units to compete with efficient combined cycle units burning low cost gas.
- In 2018, 5,522.7 MW of generation retired. The largest generator that retired in 2018 was the 614.5 MW Oyster Creek Nuclear Generating Station owned by Exelon Corporation and located in the Jersey Central Power and Light (JCPL) Zone. Of the 5,522.7 MW of generation that retired, 2,364.0 MW (42.8 percent) were located in the DAY Zone.
- There are 13,398.0 MW of generation that have requested retirement after December 31, 2018, of which 6,791.0 MW (50.7 percent) are located in the ATSI Zone. Of the ATSI generation requesting retirement, 7,829.3 MW (58.4 percent) are coal fired steam units and 4,716.0 MW (35.2 percent) are nuclear units. The largest generator pending retirement is the 1,240 MW Perry U1 Nuclear Generating Unit located in the ATSI Zone.

Generation Queue[164]

- The total MW in generation queues increased by 41,846.2 MW (57.2 percent) from 73,107.6 MW at the end of 2017 to 114,953.7 MW on December 31, 2018.
- A significant shift in the distribution of unit types within the PJM footprint continues to develop as natural gas fired units enter the queue and coal fired steam units retire. As of December 31, 2018, there were 52,804.2 MW of natural gas fired capacity active, suspended or under construction in PJM queues (including combined cycle units, CTs, RICE units, and natural gas fired steam units). As of December 31, 2018, there were only 147.0 MW of coal fired steam capacity active, suspended or under construction in PJM queues.
- As of December 31, 2018, 4,144 projects, representing 529,165.5 MW, have entered the queue process since its inception in 1998. Of those, 816 projects, representing 61,128.0 MW, went into service. Of the projects that entered the queue process, 2,392 projects, representing 353,083.9 MW (66.7 percent of the MW) withdrew prior to completion. Such projects may create barriers to entry for projects that would otherwise be completed by taking up queue positions, increasing interconnection costs and creating uncertainty.

163 See PJM "Generator Deactivations," at <http://www.pjm.com/planning/services-requests/gen-deactivations.aspx>.

164 See PJM "New Services Queue," at <https://www.pjm.com/planning/services-requests/interconnection-queues.aspx>.

Regional Transmission Expansion Plan (RTEP)

Backbone Facilities

- There are currently three backbone projects under development, Surry Skiffes Creek 500kV, and the conversion of the Marion-Bayonne and Bayway-Linden lines from 138 kV to 345 kV.[165]

Market Efficiency Process

- PJM's first market efficiency analysis was performed in 2013, prior to Order 1000. This analysis evaluated the reasons for congestion on 25 flowgates.[166] The proposal window was open from August 12, 2013, through September 26, 2013. PJM received 38 proposals from six entities. One project was approved by the PJM Board.
- Through December 31, 2018, PJM has completed two market efficiency cycles under Order No. 1000. In the first cycle, PJM received 93 proposals for 57 identified sources of congestion. In the second cycle, PJM received 96 proposals for four identified sources of congestion. The proposal window for 2018/2019 opened on November 1, 2018, and will close on February 28, 2019.
- Approved market efficiency projects periodically undergo a reevaluation process to ensure that the benefit/cost ratio continues to meet the 1.25:1 threshold. The Transource AP-South project was reevaluated in September 2017, February 2018, and again in September 2018. The project exceeded the 1.25:1 threshold in all reevaluations.
- There are significant issues with PJM's benefit/cost analysis that should be addressed prior to approval of additional projects.

PJM MISO Interregional Targeted Market Efficiency Process (TMEP)

- The first Targeted Market Efficiency Process (TMEP) analysis occurred in 2017 and included the investigation of congestion on 50 market to market flowgates. The study resulted in the evaluation of 13 potential upgrades, resulting in the recommendation of five TMEP projects. The five projects address $59 million in historical congestion, with a TMEP benefit of $99.6 million. The projects have a total cost of $20 million, with a 5.0 average benefit/cost ratio. PJM and MISO presented the five recommended projects to their boards in December, 2017, and both boards approved all five projects.[167]
- The 2018 TMEP analysis included the investigation of congestion on 61 market to market flowgates. The study resulted in the evaluation of 19 potential upgrades, resulting in the recommendation of two TMEP projects. The two projects address $25 million in historical congestion, with a TMEP benefit of $31.9 million. The projects have a total cost of $4.5 million, with a 7.1 average benefit/cost ratio. PJM and MISO presented the two recommended projects to their boards in December, 2018, and both boards approved the projects.[168]

Supplemental Transmission Projects

- Supplemental projects are "transmission expansions or enhancements that are not required for compliance with PJM criteria and are not state public policy projects according to the PJM Operating Agreement. These projects are used as inputs to RTEP models, but are not required for reliability, economic efficiency or operational performance criteria, as determined by PJM."[169] Supplemental projects are exempt from the competitive planning process.
- The average number of supplemental projects in each expected in service year increased by 520.0 percent, from 20 for years 1998 through 2007 (pre Order 890) to 124 for years 2008 through 2018 (post Order 890).

End of Life Transmission Projects

- An end of life transmission project is a project submitted for the purpose of replacing existing infrastructure that is at, or is approaching, the end of its useful life. End of life transmission projects fall under the Transmission Owner Form 715 Planning Criteria, and are currently exempt

165 See "2017 RTEP Process Scope and Input Assumptions White Paper," at 25. <http://www.pjm.com/-/media/library/reports-notices/2017-rtep/20170731-rtep-input-assumptions-and-scope-whitepaper.ashx?la=en>.

166 Historical congestion drivers are identified using the historical congestion tables presented in the 2018 *State of the Market Report for PJM*, Section 11: Congestion and Marginal Losses, historical analysis of real time constraints, the NERC Book of Flowgates and PROMOD simulations.

167 See PJM, "*MISO PJM IPSAC*" (January 12, 2018) <http://www.pjm.com/-/media/committees-groups/stakeholder-meetings/ipsac/20180112/20180112-ipsac-presentation.ashx>.

168 See PJM, "*MISO PJM IPSAC*" (January 18, 2019) <https://www.pjm.com/-/media/committees-groups/stakeholder-meetings/ipsac/20190118/20190118-ipsac-presentation.ashx>.

169 See PJM, "*Transmission Construction Status*" (January 23, 2018) <http://www.pjm.com/planning/rtep-upgrades-status/construct-status.aspx>.

from the competitive planning process.[170] End of life transmission projects are already included in the supplemental projects totals or, if included in the transmission owners' reliability plan, will be included in the baseline project list as a reliability criteria project.

- End of life transmission projects should be subject to a transparent, robust and clearly defined mechanism to permit competition to build the project.

Board Authorized Transmission Upgrades

- The Transmission Expansion Advisory Committee (TEAC) reviews internal and external proposals to improve transmission reliability throughout PJM. These proposals, which include reliability baseline, network, market efficiency and targeted market efficiency projects, but exclude supplemental and end of life projects, are periodically presented to the PJM Board of Managers for authorization.[171] In 2018, the PJM Board approved $1.98 billion in upgrades. As of December 31, 2018, the PJM Board has approved $37.1 billion in system enhancements since 1999

Transmission Competition

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

Qualifying Transmission Upgrades (QTU)

- A Qualifying Transmission Upgrade (QTU) is an upgrade to the transmission system that increases the Capacity Emergency Transfer Limit into an LDA and can be offered into capacity auctions as capacity.
- QTU projects are submitted and tracked through the PJM queue.[172] A total of 51 QTU projects have entered the queue since 2007. Of the 51 submitted QTU projects, 37 projects (72.5 percent) have been withdrawn, five (10.0 percent) are in service and nine (17.5 percent) are currently in active development.

Transmission Facility Outages

- PJM maintains a list of reportable transmission facilities. When the reportable transmission facilities need to be taken out of service, PJM transmission owners are required to report planned transmission facility outages as early as possible. PJM processes the transmission facility outage requests according to rules in PJM's Manual 3 to decide if the outage is on time or late and whether or not they will allow the outage.[173]
- There were 16,790 transmission outage requests submitted in the 2018/2019 planning period. Of the requested outages, 74.4 percent of the requested outages were planned for less than or equal to five days and 8.8 percent of requested outages were planned for greater than 30 days. Of the requested outages, 42.8 percent were late according to the rules in PJM's Manual 3.

Section 12 Recommendations

The MMU recommends improvements to the planning process:

Generation Retirements

- The MMU recommends that the question of whether Capacity Injection Rights (CIRs) should persist after the retirement of a unit, or the conversion from CP to energy only status, be addressed. The rules need to ensure that incumbents cannot exploit control of CIRs to block or postpone entry of competitors.[174] (Priority: Low. First reported 2013. Status: Not adopted.)

170 See PJM Operating Agreement Schedule 6 § 1.5.8(o).

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

172 See PJM "New Services Queue," at <https://www.pjm.com/planning/services-requests/interconnection-queues.aspx>.

173 PJM, "Manual 03: Transmission Operations," Rev. 54 (Dec. 10, 2018).

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

- The MMU recommends that 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. (Priority: Low. New recommendation. Status: Not adopted.)

Generation Queue

- The MMU recommends that barriers to entry be addressed in a timely manner in order to help ensure that the capacity market will result in the entry of new capacity to meet the needs of PJM market participants and reflect the uncertainty and resultant risks in the cost of new entry used to establish the capacity market demand curve in RPM. (Priority: Low. First reported 2012. Status: Not adopted.)
- The MMU recommends improvements in queue management including that PJM establish a review process to ensure that projects are removed from the queue if they are not viable, as well as a process to allow commercially viable projects to advance in the queue ahead of projects which have failed to make progress, subject to rules to prevent gaming. (Priority: Medium. First reported 2013. Status: Partially adopted.)
- The MMU recommends continuing analysis of the study phase of PJM's transmission planning to reduce the need for postponements of study results, to decrease study completion times, and to improve the likelihood that a project at a given phase in the study process will successfully go into service. (Priority: Medium. First reported 2014. Status: Partially adopted.)
- The MMU recommends outsourcing interconnection studies to an independent party to avoid potential conflicts of interest. Currently, these studies are performed by incumbent transmission owners under PJM's direction. This creates potential conflicts of interest, particularly when transmission owners are vertically integrated and the owner of transmission also owns generation. (Priority: Low. First reported 2013. Status: Not adopted.)

Market Efficiency Process

- The MMU recommends that 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. (Priority: Medium. First reported Q3 2018. Status: Not adopted.)
- 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. (Priority: Medium. New recommendation. Status: Not adopted.)

Supplemental Transmission Projects

- 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. (Priority: Medium. First reported 2017. Status: Not adopted.)

Transmission Competition

- 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. (Priority: Medium. First reported 2015. Status: Not adopted.)
- The MMU recommends that PJM continue to incorporate the principle that the goal of transmission planning should be the incorporation of transmission investment decisions into market driven processes as much as possible. (Priority: Low. First reported 2001. Status: Not adopted.)
- The MMU recommends the creation of a mechanism to permit a direct comparison, or competition, between transmission and generation alternatives, including which alternative is less costly and who bears the risks associated with each alternative. (Priority: Low. First reported 2013. Status: Not adopted.)

- The MMU recommends that PJM establish fair terms of access to rights of way and property, such as at substations, in order to remove any barriers to entry and permit competition between incumbent transmission providers and merchant transmission providers in the RTEP. (Priority: Medium. First reported 2014. Status: Not adopted.)
- The MMU recommends that rules be implemented to permit competition to provide financing for transmission projects. This competition could reduce the cost of capital for transmission projects and significantly reduce total costs to customers. (Priority: Low. First reported 2013. Status: Not adopted.)
- The MMU recommends that rules be implemented to require that project cost caps on new transmission projects be part of the evaluation of competing projects. (Priority: Medium. First reported 2015. Status: Not adopted.)

Transmission Facility Outages

- 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.[175] (Priority: Medium. First reported 2015. Status: Not adopted.)
- The MMU recommends that PJM reevaluate all transmission outage tickets as on time or late as if they were new requests when an outage is rescheduled and apply the standard rules for late submissions to any such outages. (Priority: Low. First reported 2014. Status: Not adopted.)
- The MMU recommends that PJM draft a clear definition of the congestion analysis required for transmission outage requests to include in Manual 3 after appropriate review. (Priority: Low. First reported 2015. Status: Not adopted.)
- 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. (Priority: Low. First reported 2015. Status: Not adopted.)
- The MMU recommends that PJM not permit transmission owners to divide long duration outages into smaller segments to avoid complying with the requirements for long duration outages. (Priority: Low. First reported 2015. Status: Not adopted.)

Section 12 Conclusion

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

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

Managing the generation queues is a highly complex process. The PJM queue evaluation process has been substantially improved in recent years and it is more efficient and effective as a result. The PJM queue evaluation process should continue to be improved to help ensure that barriers to competition for new generation investments are not created. Issues that need to be addressed include the ownership rights to CIRs, whether transmission owners should perform interconnection studies, and improvements in queue

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

management 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.

The PJM rules for competitive transmission development through the RTEP should build upon FERC Order No. 1000 to create real competition between incumbent transmission providers and merchant transmission providers. The ability of transmission owners to block competition for supplemental projects and end of life projects and reasons for that policy should be reevaluated. PJM should 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. Another element of opening competition would be to consider transmission owners' ownership of property and rights of way at or around transmission substations. In many cases, the land acquired included property intended to support future expansion of the grid. Incumbents have included the costs of the property in their rate base. Because PJM now has the responsibility for planning the development of the grid under its RTEP process, property bought to facilitate future expansion should be a part of the RTEP process and be made available to all providers on equal terms.

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

The inclusion of market efficiency transmission projects in the transmission planning process, in addition to reliability projects, effectively results in direct competition between generation and transmission to address congestion issues in the wholesale power market, including congestion in the energy and capacity markets. The role of the market efficiency process and its impact on competition should be more thoroughly evaluated. But PJM fails to explicitly address this fact in the design of the market efficiency process. While the market efficiency process and metrics require improvement, for example to ensure that all congestion is measured, the role of the market efficiency process and its impact on competition should also be more thoroughly evaluated. Building transmission under cost of service regulation already provides a significant competitive advantage to transmission over generation which is built entirely based on market prices and for which investors take the risks. The risks of cost increases for transmission projects should be incorporated in the cost benefit analysis.

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

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

The current rules governing the benefit/cost analysis evaluate competing projects with different in service dates on an asymmetric basis. Under the current rules, projects are evaluated on a present value, benefit/cost basis over a 15 year service horizon, starting with the in service date of the project. A better approach would be to establish a common end date for all evaluated competing projects so that the minimum included years for any evaluated project was 15 years. This means that if there were an RTEP year zero project and a RTEP year +2 project competing, the benefit/cost ratio analysis would include the benefits and costs for both projects for every year from RTEP year zero to RTEP+16. Under this approach all projects would be evaluated over an identical term rather than an artificially truncated term and all projects would be evaluated on a present value basis at year zero.[176]

There are currently no market incentives for transmission owners to submit and complete transmission outages in a timely and efficient manner. Requiring transmission owners to pay does not create an effective incentive when those payments are passed through to transmission customers. The process for the submission of planned transmission outages needs to be carefully reviewed and redesigned to limit the ability of transmission owners to submit transmission outages that are late for FTR auction bid submission dates and are late for the Day-Ahead Energy Market. The submission of late transmission outages can inappropriately affect market outcomes when market participants do not have the ability to modify market bids and offers.

Overview: Section 13, FTRs and ARRs

Auction Revenue Rights

Market Structure

- **Residual ARRs.** If ARR allocations are reduced as the result of a modeled transmission outage and the transmission outage ends during the relevant planning year, the result is that residual ARRs may be available. These residual ARRs are automatically assigned to eligible participants the month before the effective date. Residual ARRs are only available on paths prorated in Stage 1 of the annual ARR allocation, are only effective for single, whole months and cannot be self scheduled. Residual ARR clearing prices are based on monthly FTR auction clearing prices. Residual ARRs with negative target allocations are not allocated to participants. Instead they are removed and the model is rerun.

  In the first seven months of the 2018/2019 planning period, PJM allocated a total of 15,463.3 MW of residual ARRs, up from 14,223.4 MW in the 2017/2018 planning period, with a total target allocation of $5.7 million for the first seven months of the 2018/2019 planning period, up from $4.8 million for the 2017/2018 planning period.

- **ARR Reassignment for Retail Load Switching.** There were 25,488 MW of ARRs associated with $301,000 of revenue that were reassigned in the first seven months of the 2018/2019 planning period. There were 44,823 MW of ARRs associated with $339,500 of revenue that were reassigned for the 2017/2018 planning period.

Market Performance

- **Revenue Adequacy.** For the first seven months of the 2018/2019 planning period, the ARR target allocations, which are based on the nodal price differences from the Annual FTR Auction, were $424.9 million, while PJM collected $895.2 million from the combined Long Term, Annual and Monthly Balance of Planning Period FTR Auctions, making ARRs revenue adequate. The new allocation of surplus congestion revenue provides for revenue adequacy for FTRs first, and any remaining revenues are allocated to ARR holders. For the 2017/2018 planning period, the ARR target allocations were $573.8 million while PJM collected $601.2 million from the combined Annual and Monthly Balance of Planning Period FTR Auctions.

- **ARRs as an Offset to Congestion.** ARRs did not serve as an effective way to return congestion revenues to load. Total ARR and self scheduled FTR revenue offset only 74.5 percent of total congestion costs, which include congestion in the Day-Ahead Energy Market and the balancing energy market, for the 2011/2012 planning period through the 2016/2017 planning period, under the previous allocation of balancing congestion. In the 2017/2018 planning period, in which balancing congestion and M2M payments were directly assigned to load, total ARR and self scheduled FTR revenues offset 50.0 percent of total congestion costs. Under the new rules for surplus congestion revenue allocation beginning in the 2018/2019 planning periods, ARRs, self scheduled FTRs and surplus congestion revenue would offset 74.2 percent of total congestion costs. The goal of the FTR market design should be to ensure that load has the rights to 100 percent of the congestion revenues.

176 See "Comments of the Independent Market Monitor for PJM," (January 11, 2019) <http://www.monitoringanalytics.com/Filings/2019/IMM_Comments_Docket_No_ER19-80_20190111.pdf>.

Financial Transmission Rights

Market Structure

- **Supply.** In a given auction, market participants can sell FTRs that they have acquired in preceding auctions. In the Monthly Balance of Planning Period FTR Auctions for the first seven months of the 2018/2019 planning period, total participant FTR sell offers were 5,705,610 MW, up from 3,228,291 MW for the same period during the 2017/2018 planning period.
- **Demand.** In the 2018/2021 Long Term FTR Auction, total FTR buy bids were 2,052,820 MW, down 5.7 percent from 2,176,871 MW in the previous planning period. There were 2,907,583 MW of buy and self scheduled bids in the 2018/2019 Annual FTR Auction, up 33.6 percent from 2,176,871 MW the previous planning period. The total FTR buy bids from the Monthly Balance of Planning Period FTR Auctions for the first seven months of the 2018/2019 planning period increased 3.5 percent from 14,104,482 MW for the same time period of the prior planning period, to 13,631,502 MW.
- **Patterns of Ownership.** For the 2018/2021 Long Term FTR Auction, financial entities purchased 72.0 percent of prevailing flow FTRs and 76.5 percent of counter flow FTRs. For the 2018/2019 Annual FTR Auction, financial participants purchased 66.9 percent of all prevailing flow FTRs and 84.2 percent of all counter flow FTRs. For the Monthly Balance of Planning Period Auctions, financial entities purchased 75.5 percent of prevailing flow and 82.6 percent of counter flow FTRs for January through December of 2018. Financial entities owned 70.9 percent of all prevailing and counter flow FTRs, including 63.7 percent of all prevailing flow FTRs and 81.7 percent of all counter flow FTRs during the period from January through December 2018.

Market Behavior

- **FTR Forfeitures.** For the period of January 19, 2017, through December 31, 2018, except November 2018 which is not yet settled, total FTR forfeitures were $13.1 million.
- **Credit.** There were 14 collateral defaults in 2018 not involving GreenHat Energy, LLC, for a total of $643,371. Most collateral defaults were cured promptly. There were 74 payment defaults in 2018 not involving GreenHat Energy, LLC for a total of $136,120, which resulted in the default of Amerigreen Energy, Inc. on June 12, 2018.[177]

  On June 21, 2018, GreenHat Energy, LLC was declared in default for two collateral calls totaling $2.8 million and two payment defaults totaling $3.9 million.[178] GreenHat held a large FTR position which, according to then applicable tariff provisions, must be liquidated in the FTR auctions closest to the effective dates of the positions held.[179] The net gain or loss on these liquidated positions will be added to the payment default amount that will then be allocated to PJM members according to OA Sections 15.1.2A(1) and 15.2.2. On January 30, 2019, FERC denied a waiver request filed by PJM on July 26, 2018, asking that FERC only require PJM to liquidate FTRs for the prompt months to allow member discussion on how to proceed with GreenHat's large FTR portfolio.[180] Under the assumption of a waiver, members had elected to settle GreenHat's FTR portfolio at the time the FTRs are due, so default allocation assessment charges would continue to accrue through May 2021. PJM estimates a liquidation cost to members of $250-$300 million under the tariff rules applicable at the time of the default.[181]

Market Performance

- **Volume.** The 2018/2021 Long Term FTR Auction cleared 345,506 MW (16.8 percent) of FTR buy bids, up 16.3 percent from 297,083 MW (13.6 percent) in the 2017/2020 Long Term FTR Auction. The Long Term FTR Auction also cleared 42,555 MW (17.8 percent) of FTR sell offers, compared to 36,782 (17.6 percent), a 16.7 percent increase.

  In the Annual FTR Auction for the 2018/2019 planning period 615,254 MW (21.2 percent) of buy and self schedule bids cleared, up 19.9 percent from 615,254 MW (22.3 percent) for the previous planning period. In the first seven months of the 2018/2019 planning period Monthly Balance of Planning Period FTR Auctions cleared 2,039,265

177 Daugherty, Suzanne, email sent to the MC, MRC, CS and MSS email distribution list, "PJM Member Default – Amerigreen Energy, Inc.," (June 13, 2018).

178 Daugherty, Suzanne, Email sent to the MC, MRC, CS, and MSS email distribution list, "Notification of GreenHat Energy, LLC Payment Default," (June 22, 2018).

179 "PJM Manual 6: Financial Transmission Rights," Rev. 21 (Dec. 6, 2018).

180 See 166 FERC ¶ 61,072, *reh'g pending.*

181 *See* Presentation "Update on FERC Order Denying PJM's Request for Waiver re: Liquidating FTR Positions of Defaulted Member," MRC. February 21, 2019.

MW (14.5 percent) of FTR buy bids and 1,181,126 MW (20.7 percent) of FTR sell offers.

- **Price.** The weighted average buy bid FTR price in the 2018/2021 Long Term FTR Auction was $0.03 per MW, down from $0.04 per MW for the 2017/2020 planning period. The weighted average buy bid FTR price in the Annual FTR Auction for the 2018/2019 planning period was $0.59 per MW, up from $0.51 per MW in the 2017/2018 planning period. The weighted average buy bid cleared FTR price in the Monthly Balance of Planning Period FTR Auctions for the first seven months of the 2018/2019 planning period was $0.13, up from $0.11 per MW for the same period in the 2017/2018 planning period.
- **Revenue.** The 2018/2021 Long Term FTR Auction generated $29.6 million of net revenue for all FTRs, up from $26.7 million for the 2017/2020 Long Term FTR Auction. The 2018/2019 Annual FTR Auction generated $822.6 million in net revenue, up from $542.2 million for the 2017/2018 Annual FTR Auction. The Monthly Balance of Planning Period FTR Auctions generated $47.3 million in net revenue for all FTRs for the first seven months of the 2018/2019 planning period, up from $26.4 million for the same time period in the 2017/2018 planning period.
- **Revenue Adequacy.** FTRs were paid at 100 percent of the target allocation level for the first seven months of the 2018/2019 planning period. This level of FTR funding was at least partially a result of FERC redefining the FTR congestion calculation to exclude balancing congestion and M2M payments.
- **Profitability.** FTR profitability is the difference between the revenue received for an FTR and the cost of the FTR. In the first seven months of the 2018/2019 planning period, physical entities made $217.2 million in profits, while receiving $91.3 million in returned congestion from self scheduled FTRs, and financial entities made $93.7 million in profits.

Section 13 Recommendations

- The MMU recommends that the ARR/FTR design be modified to ensure that the rights to all congestion revenues are assigned to load. (Priority: High. First reported 2015. Status: Not adopted.)
- The MMU recommends that the Long Term FTR product be eliminated. (Priority: High. First reported Q3, 2018. Status: Not adopted.)
- 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. (Priority: High. First reported 2017. Status: Not adopted.)
- The MMU recommends that the 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. (Priority: High. First reported 2017. Status: Not adopted.)
- The MMU recommends that all FTR auction revenue be distributed to ARR holders monthly, regardless of FTR funding levels. (Priority: High. First reported 2015. Status: Not adopted.)
- The MMU recommends that, under the current FTR design, all congestion revenue in excess of FTR target allocations be distributed to ARR holders on a monthly basis. (Priority: High. First reported Q1, 2018. Status: Not adopted.)
- The MMU recommends that FTR auction revenues not be used to buy counter flow FTRs for the purpose of improving FTR payout ratios.[182] (Priority: High. First reported 2015. Status: Not adopted.)
- The MMU recommends that all historical generation to load paths be eliminated as a basis for allocating ARRs. (Priority: High. First reported 2015. Status: Partially adopted.)
- The MMU recommends that PJM eliminate portfolio netting to eliminate cross subsidies among FTR market participants. (Priority: High. First reported 2012. Status: Not adopted. Rejected by FERC.)
- The MMU recommends that PJM eliminate subsidies to counter flow FTRs by applying the payout ratio to counter flow FTRs in the same way the payout ratio is applied to prevailing flow FTRs. (Priority: High. First reported 2012. Status: Not adopted.)

182 See "PJM Manual 6: Financial Transmission Rights," Rev. 21 (Dec. 6, 2018) .

- The MMU recommends that PJM eliminate geographic cross subsidies. (Priority: High. First reported 2013. Status: Not adopted.)
- The MMU recommends that PJM examine the mechanism by which self scheduled FTRs are allocated when load switching among LSEs occurs throughout the planning period. (Priority: Low. First reported 2011. Status: Not adopted.)
- The MMU recommends that PJM improve transmission outage modeling in the FTR auction models, including the use of probabilistic outage modeling. (Priority: Low. First reported 2013. Status: Not adopted.)
- The MMU recommends that PJM reduce FTR sales on paths with persistent overallocation of FTRs including clear rules for what defines persistent overallocation and how the reduction will be applied. (Priority: High. First reported 2013. Status: Partially adopted, 2014/2015 planning period.)
- The MMU recommends that PJM and its members continue to review the management of a defaulted member's FTR portfolio, including options other than immediate liquidation. (Priority: High. First reported Q2, 2018. Status: Not adopted.)
- The MMU recommends that PJM continue to evaluate the bilateral indemnification rules and any asymmetries they may create. (Priority: Low. New recommendation. Status: Not adopted.)
- The MMU recommends that PJM reexamine the source and sink node combinations available in the FTR market. (Priority: High. New recommendation. Status: Not adopted.)
- 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. (Priority: High. New recommendation. Status: Not adopted.)
- The MMU recommends that the direct customer request approach for creating and allocating IARR should be eliminated from PJM's tariff. (Priority: Low. New recommendation. Status: Not adopted.)

Section 13 Conclusion

The annual ARR allocation should be designed to ensure that the rights to all congestion revenues are assigned to firm transmission service customers, without requiring contract path physical transmission rights that are inconsistent with the network based delivery of power and the actual way congestion is generated in a security constrained LMP markets. The fixed charges paid for firm transmission services result in the transmission system which provides physically firm transmission service, which results in the delivery of low cost generation, which results in load paying congestion revenues, in an LMP market.

Revenue adequacy is misunderstood and generally incorrectly defined. Revenue adequacy has received a lot of attention in the PJM FTR Market and conclusions based on the incorrect definition have led to significant changes in the design of the ARR/FTR market that have distorted the function and purpose of ARRs and FTRs as a means of allocating congestion and congestion rights. Correctly defined, revenue adequacy for ARRs means that ARRs have the rights to 100 percent of congestion revenue. FTR holders, with the creation of ARRs, do not have a right to receive revenues equal to CLMP differentials on individual FTR paths.

The current ARR/FTR design does not serve as an efficient way to ensure that load receives the rights to all the congestion revenues and has the ability to receive the auction revenues associated with all the potential congestion revenues. Total ARR and self scheduled FTR revenue offset only 65.3, 90.3, 100.0, 50.0 percent of total congestion costs including congestion in the Day-Ahead Energy Market and the balancing energy market for the 2014/2015, 2015/2016, 2016/2017, 2017/2018 planning years. If surplus through December 2018 were distributed, total ARR and self scheduled FTR revenue would offset 74.2 percent of total congestion costs for the first seven months of the 2018/2019 planning period.

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

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

Load should never be required to subsidize payments to FTR holders, regardless of the reason. Such subsidies have been suggested repeatedly.[183] The FERC order of September 15, 2016, introduced a subsidy to FTR holders at the expense of ARR holders.[184] The order requires PJM to ignore balancing congestion when calculating total congestion dollars available to fund FTRs. As of the 2017/2018 planning period, as a result of the FERC order, balancing congestion and M2M payments are assigned to load, rather than to FTR holders. The Commission's order shifts substantial revenue from load to the holders of FTRs and reduces the ability of load to offset congestion. This approach ignores the fact that loads must pay both day-ahead and balancing congestion, and that congestion is defined, in an accounting sense, to equal the sum of day-ahead and balancing congestion. Eliminating balancing congestion from the FTR revenue calculation requires load to pay twice for congestion. Load will pay for the physical transmission system, will pay in excess of generator revenues and will pay negative balancing congestion again. The result will be that load will get back less than total congestion.

These changes were made in order to increase the payout to holders of FTRs who are not loads. In other words, load will continue to be the source of all the funding for FTRs, while payments to FTR holders who did not receive ARRs exceed total congestion on their FTR paths and result in profits to FTR holders. Increasing the payout to FTR holders is not a supportable market objective. FTR holders should receive actual congestion on the relevant FTR paths and PJM should not artificially restrict the available paths.

Load was made significantly worse off as a result of the changes made to the FTR/ARR process by PJM based on the FERC order of September 15, 2016. ARR revenues were significantly reduced for the 2017/2018 FTR Auction, the first auction under the new rules. ARRs and self scheduled FTRs offset 50.0 percent of total congestion costs for the 2017/2018 planning period rather than the 60.5 percent offset that would have occurred under the prior rules, a difference of $125.8 million. There was a significant amount of congestion in January 2018 which adversely affected the congestion offset value of ARRs. ARR revenue is fixed at annual auction prices, but congestion revenue varies with market conditions. If these allocation rules had been in place beginning with the 2011/2012 planning period, ARR holders would have received a total of $1,160.0 million less in congestion offsets from the 2011/2012 through the 2017/2018 planning period. The total overpayment to FTR holders for the 2011/2012 through 2017/2018 planning period would have been $1,315.1 million.

The actual underpayment to load and the overpayment to FTR holders was a result of several rules, all of which mean the transfer of revenues to FTR holders and the shifting of costs to load. Load is required to pay for balancing congestion, which significantly increases costs to load and significantly increases revenues paid to FTR holders while degrading the ability of ARRs to provide a predictable offset to congestion costs. Surplus revenues from the FTR auction are not assigned to ARR holders, but are used by PJM to clear counter flow FTRs in the Monthly FTR Auctions in order to make it possible to sell more prevailing flow FTRs. Under the prior rules, surplus revenues in the day-ahead market were assigned to FTR holders along with surplus auction revenues.

A rule change was implemented by PJM to offset the more egregious effects of the allocation of balancing congestion to load. Beginning with the 2018/2019 planning period, surplus revenues in the day-ahead market and surplus auction revenue are assigned to

183 See FERC Dockets Nos. EL13-47-000 and EL12-19-000.
184 See 156 FERC ¶ 61,180 (2016), *reh'g denied*, 156 FERC ¶ 61,093 (2017).

FTR holders only up to revenue adequacy, and then distributed to ARR holders.[185]

All congestion revenue belongs to ARR holders, and PJM's new surplus congestion allocation rule is an attempt to get closer to that goal. However, under the rules, ARR holders will only be allocated this surplus after full funding of FTRs is accomplished. The new rules, while an improvement, do not fully recognize ARR holders' primary rights to surplus congestion revenue. If this rule had been in effect for the 2017/2018 planning period, ARRs and FTRs would have offset 81.1 percent of total congestion rather than 50.0 percent. For the first seven months of the 2018/2019 planning period, if the surplus auction revenue were distributed to load on a monthly basis, load would have offset 74.2 percent of congestion costs rather than 71.1 percent of their congestion costs without the surplus.

The overallocation of Stage 1A ARRs results in FTR overallocations on the same facilities. While Stage 1A overallocation has been reduced, Stage 1A ARR overallocation is a source of reduced revenue and cross subsidy.

The MMU recommends that the basis for the Stage 1A assignments be reviewed and made explicit and that the role of out of date generation to load paths be reviewed beyond the replacement of retired generation that was implemented. There is a reason that transmission is not built to address the Stage 1A overallocation issue. PJM's transmission planning process (RTEP) does not identify a need for new transmission because many of the over allocations are due to outages in the FTR model, or are flowgates, not actual system limitations. Capacity issues do not persist if the modeled outages are removed, so there is no need to expand the transmission system to support them. The Stage 1A overallocation issue is a fiction based on the use of outdated and irrelevant generation to load paths to assign Stage 1A rights that have nothing to do with actual power flows.

In addition to addressing these issues, the approach to the question of FTR funding should also examine the fundamental reasons that there has been a significant and persistent difference between day-ahead and balancing congestion. The MMU recommends that the transmission modeling in the FTR auction and persistent FTR path overallocation issues be reviewed and modifications implemented. Regardless of how these issues are addressed, funding issues that persist as a result of modeling differences and flaws in the design of the FTR Market should be borne by FTR holders operating in the voluntary FTR Market and not imposed on load through the mechanism of balancing congestion.

It is not clear, in a competitive market, why participation in the Long Term FTR Auction continues to be very low for the second and third year long term product. In a competitive market the price of Long Term FTRs would be expected to converge with the prices of Annual FTRs, but there has been a persistent, wide divergence that has made the purchase of Long Term FTRs persistently very profitable. Recent changes to improve the modeling of the next year's auction model and include an offline ARR allocation model are steps in the right direction, but do not do enough to guarantee ARR holders' rights to the congestion being auctioned in the Long Term FTR Auction.

The MMU recommends that the Long Term FTR product be eliminated. If the Long Term FTR product is not eliminated, the MMU recommends that 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. This would ensure ARR holders' rights to congestion while maintaining the ability for participants to purchase congestion offsets for future planning periods.

185 163 FERC ¶61,165 (2018).

Recommendations

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

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

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

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

- **Adopted:** PJM has implemented the recommendation made by the MMU.
- **Partially adopted:** PJM has implemented part of the recommendation made by the MMU.
- **Not adopted:** PJM does not plan to implement the recommendation made by the MMU, or has not yet implemented any part of the recommendation made by the MMU. Where the subject of the recommendation is pending stakeholder, FERC, or court action, that status is noted.

New Recommendations

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

In this *2018 State of the Market Report for PJM*, the MMU includes 36 new recommendations made in 2018, 17 of which are new in this 2018 annual report.[7]

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

6 18 CFR § 35.28(g)(3)(ii)(A); see also OATT Attachment M § IV.D.
7 New recommendations include all MMU recommendations that were reported for the first time in the *2018 State of the Market Report for PJM* or in any of the three quarterly state of the market reports that were published in 2018.

New Recommendations from Section 3, 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. (Priority: Medium. First reported Q3, 2018. Status: Not adopted.)
- The MMU recommends that PJM clearly define the business rules that apply to the unit specific parameter adjustment process, including PJM's implementation of the tariff rules in the PJM manuals to ensure market sellers know the requirements for their resources. (Priority: Low. First reported Q3, 2018. Status: Not adopted.)
- 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 as the basis for Fuel Cost Policies but should not be required. (Priority: Low. First reported Q1, 2018. Status: Not adopted.)
- 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. (Priority: Low. First reported Q1, 2018. Status: Not adopted.)
- The MMU recommends that PJM update the tariff to clarify that all generation resources are subject to unit specific parameter limits on their cost-based offers using the same standard and process as capacity performance capacity resources. (Priority: Medium. New recommendation. Status: Not adopted.)
- 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. (Priority: Medium. New recommendation. Status: Not adopted.)
- 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. (Priority: High. New recommendation. Status: Not adopted.)

New Recommendations from Section 4, Energy Uplift

- The MMU recommends that uplift should only be paid based on operating parameters that reflect the flexibility of the benchmark new entrant unit (CONE unit) in the PJM Capacity Market. (Priority: High. First reported Q1, 2018. Status: Not adopted.)
- The MMU recommends eliminating the use of intraday segments to define eligibility for uplift payments and returning to evaluating the need for uplift on a daily, 24 hours, basis. (Priority: High. First reported Q1, 2018. Status: Not adopted.)
- The MMU recommends that PJM pay uplift based on the offer at the lower of the actual unit output or the dispatch signal MW. (Priority: Medium. First reported Q1, 2018. Status: Not adopted.)
- 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. (Priority: Medium. First reported Q1, 2018. Status: Not adopted.)
- 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 (Priority: Medium. New recommendation. Status: Not adopted.)

New Recommendation from Section 5, 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. (Priority: Medium. First reported Q3, 2018. Status: Not adopted.)

New Recommendations from Section 6, 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. (Priority: Medium. New recommendation. Status: Not adopted.)
- The MMU recommends that 30 minute pre-emergency and emergency demand response be considered to be 30 minute reserves. (Priority: Medium. New recommendation. Status: Not adopted.)
- 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 with the existing lag. (Priority: Medium. New recommendation. Status: Not adopted.)

New Recommendations from Section 8, Environmental and Renewable Energy Regulations

- The MMU recommends that the Commission reconsider its disclaimer of jurisdiction over RECs markets because, given market changes since that decision, it is clear that RECs materially affect jurisdictional rates. (Priority: High. New recommendation. Status: Not adopted.)
- 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. (Priority: Medium. New recommendation. Status: Not adopted.)
- The MMU recommends that jurisdictions with a renewable portfolio standard make the price and quantity data on supply and demand more transparent. (Priority: Low. First reported Q2, 2018. Status: Not adopted.)

New Recommendations from Section 10, Ancillary Service Markets

- The MMU recommends that the $7.50 margin be eliminated from the definition of the cost of tier 2 synchronized reserve because it is a markup and not a cost. (Priority: Medium. First reported Q3, 2018. Status: Not adopted.)
- 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. (Priority: Medium. First reported Q3, 2018. Status: Not adopted.)
- The MMU recommends that aggregation not be permitted to offset unit specific penalties for failure to respond to a synchronized reserve event. (Priority: Medium. First reported Q3, 2018. Status: Not adopted.)
- The MMU recommends that offers in the DASR Market be based on opportunity cost only in order to eliminate market power. (Priority: Low. First reported 2009. Modified Q3, 2018. Status: Not adopted.)
- The MMU recommends that payments for reactive capability, if continued, be based on the 0.90 power factor that PJM has determined is necessary. (Priority: Medium. First reported Q3, 2018. Status: Not adopted.)
- The MMU recommends that PJM eliminate the use of Degree of Generator Performance (DGP) in the synchronized reserve market solution and improve the actual tier 1 estimate. If PJM continues to use DGP, DGP should be documented in PJM's manuals. (Priority: Medium. New recommendation. Status: Not adopted.)
- 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. (Priority: Medium. New recommendation. Status: Not adopted.)

New Recommendations from Section 12, Generation and Transmission 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. (Priority: Medium. First reported Q3, 2018. Status: Not adopted.)
- 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. (Priority: Low. New recommendation. Status: Not adopted.)
- 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. (Priority: Medium. New recommendation. Status: Not adopted.)

New Recommendations from Section 13, Financial Transmission and Auction Revenue Rights

- The MMU recommends that PJM continue to review the management of a defaulted member's FTR portfolio, including options other than liquidation. (Priority: High. First reported Q2, 2018. Status: Not adopted.)
- The MMU recommends that, under the current FTR design, all congestion revenue in excess of FTR target allocations be distributed to ARR holders on a monthly basis. (Priority: High. First reported Q1, 2018. Status: Not adopted.)
- The MMU recommends that the Long Term FTR product be eliminated. (Priority: High. First reported Q3, 2018. Status: Not adopted.)
- The MMU recommends that PJM continue to evaluate the bilateral indemnification rules and any asymmetries they may create. (Priority: Low. New recommendation. Status: Not adopted.)
- The MMU recommends that PJM examine the source and sink node combinations available in the FTR market, and to ensure they represent paths that may actually face congestion. (Priority: High. New recommendation. Status: Not adopted.)
- 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. (Priority: High. New recommendation. Status: Not adopted.)
- The MMU recommends that the direct customer request approach for creating and allocating IARRs should be eliminated from PJM's tariff. (Priority: Low. New recommendation. Status: Not adopted.)

History of MMU Recommendations

The MMU began making recommendations to PJM in the 1999 State of the Market Report. Since that time, the MMU has made 275 recommendations in the State of the Market Reports. In 2014, the MMU began including a priority and status with each recommendation. In this *2018 State of the Market Report for PJM*, the MMU has reviewed all past recommendations, assigned priority and determined their current status.

For the review of past recommendations, the MMU has refined the status assigned to each recommendation. The MMU uses additional definitions:

- **Partially Adopted (Continued Recommendation):** PJM has implemented part of the recommendation made by the MMU, and the MMU continues to recommend total adoption of the recommendation. These recommendations continue to be included in the main sections of this report;
- **Partially Adopted (Recommendation Closed):** PJM has implemented part of the recommendation made by the MMU, and the MMU has chosen to discontinue making the recommendation going forward. These recommendations are no longer included in the main sections of this report;
- **Not Adopted (Pending before FERC):** PJM has not yet implemented any part of the recommendation made by the MMU, but the subject of the recommendation is pending FERC action;
- **Not Adopted (Stakeholder Process):** PJM has not yet implemented any part of the recommendation made

by the MMU, but the subject of the recommendation is pending stakeholder action;

- **Replaced by Newer Recommendation:** a recommendation that was discontinued when the MMU modified the recommendation; and
- **Withdrawn:** The MMU no longer makes the recommendation.

Table 2-1 shows the status of all recommendations reported by the MMU from 1999 through 2018. Over that time, 21 percent of all MMU recommendations have been adopted, 33 percent have been adopted or partially adopted, and 60 percent are not adopted. Of the 75 high priority recommendations, 21 (28 percent) have been adopted. Table 2-1 includes past recommendations that are no longer included in this report.

Table 2-1 Status of MMU reported recommendations: 1999 through 2018

Status	Priority High	Priority Medium	Priority Low	Total	Percent of Total
Adopted	21	18	18	57	20.7%
Partially Adopted - Stakeholder Process	0	0	0	0	0.0%
Partially Adopted - FERC	1	0	0	1	0.4%
Partially Adopted (Continued Recommendation)	7	12	5	24	8.7%
Partially Adopted (Recommendation Closed)	2	3	5	10	3.6%
Partially Adopted (Total)	10	15	10	35	12.7%
Not Adopted	37	74	44	155	56.4%
Not Adopted (Pending before FERC)	4	2	0	6	2.2%
Not Adopted (Stakeholder Process)	1	3	1	5	1.8%
Not Adopted (Total)	42	79	45	166	60.4%
Replaced by Newer Recommendation	1	7	3	11	4.0%
Withdrawn	1	3	2	6	2.2%
Total	75	122	78	275	100.0%

Complete List of Current MMU Recommendations

The recommendations are explained in each section of the report.

Section 3, Energy Market

Market Power

- The MMU recommends that the market rules explicitly require that offers in the 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. (Priority: Medium. First reported 2009. Status: Not adopted.)
- The MMU recommends that PJM require that all fuel cost policies be algorithmic, verifiable, and systematic, and accurately reflect short run marginal costs. (Priority: Medium. First reported 2016. Status: Not adopted.)
- The MMU recommends that the 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 as the basis for Fuel Cost Policies but should not be required. (Priority: Low. First reported Q1, 2018. Status: Not adopted.)
- 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. (Priority: Low. First reported Q1, 2018. Status: Not adopted.)
- 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. (Priority: Medium. First reported 2016. Status: Not adopted.)
- The MMU recommends removal of all use of FERC System of Accounts in the Cost Development Guidelines. (Priority: Medium. First reported 2016. Status: Not adopted.)
- The MMU recommends the removal of all use of cyclic starting and peaking factors from the Cost Development Guidelines. (Priority: Medium. First reported 2016. Status: Not adopted.)
- The MMU recommends the removal of all labor costs from the Cost Development Guidelines. (Priority: Medium. First reported 2016. Status: Not adopted.)
- 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. (Priority: Medium. First reported 2016. Status: Not adopted.)

- The MMU recommends the removal of nuclear fuel and nonfuel operations and maintenance costs that are not short run marginal costs from the Cost Development Guidelines. (Priority: Medium. First reported 2016. Status: Not adopted.)
- The MMU recommends revising the pumped hydro fuel cost calculation to include day-ahead and real-time power purchases. (Priority: Low. First reported 2016. Status: Not adopted.)
- 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. (Priority: Medium. First reported 2016. Status: Adopted, 2018.)
- The MMU recommends removing the catastrophic designation for force majeure fuel supply limitations in Schedule 2. (Priority: Medium. First reported 2016. Status: Not adopted.)
- The MMU recommends that the rules governing the application of the TPS test be clarified and documented. The TPS test application in the Day-Ahead Energy Market is not documented. (Priority: High. First reported 2015. Status: Partially adopted.)
- The MMU recommends that PJM require every market participant to make available at least one cost schedule based on the same hourly fuel type(s) and parameters at least as flexible as their offered price schedule. (Priority: Medium. First reported 2015. Status: Not adopted.)
- The MMU recommends, in order to ensure effective market power mitigation when the TPS test is failed, that markup be constant across the full MWh range of price and cost-based offers. (Priority: High. First reported 2015. Status: Not adopted.)
- 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. (Priority: High. First reported 2015. Status: Not adopted.)
- The MMU recommends that PJM retain the $1,000 per MWh offer cap in the PJM energy market except when cost-based offers exceed $1,000 per MWh, and retain other existing rules that limit incentives to exercise market power. (Priority: High. First reported 1999. Status: Partially adopted, 1999, 2017.)
- The MMU recommends the elimination of FMU and AU adders. FMU and AU adders no longer serve the purpose for which they were created and interfere with the efficient operation of PJM markets. (Priority: Medium. First reported 2012. Status: Partially adopted, 2014.)
- 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.[8] (Priority: Medium. First reported 2012. Status: Not adopted.)

Capacity Performance Resources

- 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. (Priority: Medium. First reported 2015. Status: Not adopted.)
- The MMU recommends that the parameters which determine nonperformance charges and the amounts of uplift payments should reflect the flexibility goals of the capacity 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. (Priority: Medium. First reported 2015. Status: Partially adopted.)

8 This recommendation was accepted by PJM and filed with FERC in 2014 as part of the capacity performance updates to the RPM. See Schedule 1, Section 1.10.1A(d), Revisions to the PJM Open Access Transmission Tariff and PJM Operating Agreement (Marked/Redline Format), EL15-29-000 (December 12, 2014). FERC rejected the proposed change. See 151 FERC ¶ 61,208 at P 476 (2015).

- 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. (Priority: Low. First reported 2016. Status: Not adopted.)
- The MMU recommends that PJM document how LMPs are calculated when demand response is marginal. (Priority: Low. First reported 2014. Status: Not Adopted.)
- The MMU recommends that PJM not 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. (Priority: Medium. First reported Q3, 2018. Status: Not adopted.)
- The MMU recommends that PJM clearly define the business rules that apply to the unit specific parameter adjustment process, including PJM's implementation of the tariff rules in the PJM manuals to ensure market sellers know the requirements for their resources. (Priority: Low. First reported Q3, 2018. Status: Not adopted.)
- The MMU recommends that PJM update the tariff to clarify that all generation resources are subject to unit specific parameter limits on their cost-based offers using the same standard and process as capacity performance capacity resources. (Priority: Medium. New recommendation. Status: Not adopted.)
- 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. (Priority: Medium. New recommendation. Status: Not adopted.)

Accurate System Modeling

- The MMU recommends that PJM explicitly state its policy on the use of transmission penalty factors including: the level of the penalty factors; the triggers for the use of the penalty factors; the appropriate line ratings to trigger the use of penalty factors; the allowed duration of the violation; the use of constraint relaxation logic; and when the transmission penalty factors will be used to set the shadow price. (Priority: Medium. First reported 2015. Status: Partially adopted.)
- The MMU recommends that PJM routinely review all transmission facility ratings and any changes to those ratings to ensure that the normal, emergency and load dump ratings used in modeling the transmission system are accurate and reflect standard ratings practice. (Priority: Low. First reported 2013. Status: Partially adopted.)
- The MMU recommends that PJM update the outage impact studies, the reliability analyses used in RPM for capacity deliverability, and the reliability analyses used in RTEP for transmission upgrades to be consistent with the more conservative emergency operations (post contingency load dump limit exceedance analysis) in the energy market that were implemented in June 2013. (Priority: Low. First reported 2013. Status: Not adopted.)
- The MMU recommends that PJM include in the tariff or appropriate manual an explanation of the initial creation of hubs, the process for modifying hub definitions and a description of how hub definitions have changed.[9] [10] (Priority: Low. First reported 2013. Status: Not adopted.)
- The MMU recommends that all buses with a net withdrawal be treated as load for purposes of calculating load and load-weighted LMP. 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. (Priority: Low. First reported 2013. Status: Not adopted.)
- The MMU recommends that PJM identify and collect data on available behind the meter generation resources, including nodal location information and relevant operating parameters. (Priority: Low. First reported 2013. Status: Partially adopted.)
- The MMU recommends that PJM increase the interaction of outage and operational restrictions

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

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

data submitted by Market Participants via eDART/eGADs and offer data submitted via Markets Gateway. (Priority: Low. First reported 2017. Status: Not adopted.)

Transparency

- 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. (Priority: Medium. First reported 2015. Status: Partially adopted.)
- The MMU recommends that PJM continue to enhance its posting of market data to promote market efficiency. (Priority: Medium. First reported 2005. Status: Partially adopted.)
- 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. (Priority: High. New recommendation. Status: Not adopted.)

Section 4, Energy Uplift

- The MMU recommends that uplift be paid only based on operating parameters that reflect the flexibility of the benchmark new entrant unit (CONE unit) in the PJM Capacity Market. (Priority: High. First reported Q1, 2018. Status: Not adopted.)
- 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. (Priority: Medium. First reported 2013. Status: Not adopted.)
- 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. (Priority: Medium. First reported 2015. Status: Not adopted.)
- 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. (Priority: Medium. First Reported 2016. Status: Not adopted.)
- 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. (Priority: Medium. First Reported 2012. Status: Not adopted.)
- The MMU recommends eliminating intraday segments from the calculation of uplift payments and returning to calculating the need for uplift based on the entire 24 hour operating day. (Priority: High. First reported Q1, 2018. Status: Not adopted.)
- The MMU recommends the elimination of 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. (Priority: Medium. First reported 2013. Status: Not adopted.)
- The MMU recommends enhancing the current energy uplift allocation rules to reflect the recommended elimination of day-ahead operating reserves, the timing of commitment decisions and the commitment reasons. (Priority: High. First reported 2012. Status: Not adopted.)
- The MMU recommends reincorporating the use of net regulation revenues as an offset in the calculation of balancing operating reserve credits. (Priority: Medium. First reported 2009. Status: Not adopted. Stakeholder process.)
- 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. (Priority: Low. First reported 2013. Status: Not adopted. Stakeholder process.)
- The MMU recommends three modifications to the energy lost opportunity cost calculations:

  - The MMU recommends calculating LOC based on 24 hour daily periods for combustion turbines and diesels scheduled in the Day-Ahead Energy Market, but not committed in real time. (Priority: Medium. First reported 2014. Status: Not adopted.)
  - The MMU recommends that units scheduled in the Day-Ahead Energy Market and not committed in real time should be compensated for LOC based on their real-time desired and achievable output, not their scheduled day-ahead output. (Priority: Medium. First reported 2015. Status: Not adopted.)
  - The MMU recommends that only flexible fast start units (startup plus notification times of 10 minutes or less) and short minimum run times (one hour or less) be eligible by default for the LOC compensation to units scheduled in the Day-Ahead Energy Market and not committed in real time. Other units should be eligible for LOC compensation only if PJM explicitly cancels their day-ahead commitment. (Priority: Medium. First reported 2015. Status: Not adopted.)
- The MMU recommends that up to congestion transactions be required to pay energy uplift charges for both the injection and the withdrawal sides of the UTC. (Priority: High. First reported 2011. Status: Not adopted.)
- The MMU recommends eliminating the use of internal bilateral transactions (IBTs) in the calculation of deviations used to allocate balancing operating reserve charges. (Priority: High. First reported 2013. Status: Adopted 2018.[11])
- 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. (Priority: Medium. First reported 2014. Status: Not adopted. Stakeholder process.)
- The MMU recommends that the total cost of providing reactive support be categorized and allocated as reactive services. Reactive services credits should be calculated consistent with the balancing operating reserve credit calculation. (Priority: Medium. First reported 2012. Status: Not adopted. Stakeholder process.)
- The MMU recommends including real-time exports and real-time wheels in the allocation of the cost of providing reactive support to the 500 kV system or above, in addition to real-time load. (Priority: Low. First reported 2013. Status: Not adopted.)
- The MMU recommends modifications to the calculation of lost opportunity costs credits paid to wind units. The lost opportunity costs credits paid to wind units should be based on the lesser of the desired output, the estimated output based on actual wind conditions and the capacity interconnection rights (CIRs). The MMU recommends that PJM allow wind units to request CIRs that reflect the maximum output wind units want to inject into the transmission system at any time. (Priority: Low. First reported 2012. Status: Not adopted.)
- 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 the Manual 11 attachment C procedure with the implementation of hourly offers (ER16-372-000). (Priority: Medium. First reported 2016. Status: Not adopted.[12])
- 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. (Priority: Medium. First reported 2011. Status: Partially adopted.)
- 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

11 As of November 1, 2018, internal bilateral transactions are no longer used for the calculation of deviations for purposes of allocating balancing operating reserve charges. See the *2018 State of the Market Report for PJM*, Section 3: "Energy Market" at "Internal Bilateral Transactions" for an analysis of the impact of this change on virtual bidding activity.

12 Although this recommendation has not been adopted exactly as recommended by the MMU, the implementation of hourly offers by PJM has effectively adopted this recommendation.

credits by unit in the PJM region. (Priority: High. First reported 2013. Status: Partially adopted.[13])

- The MMU recommends that PJM pay uplift based on the offer at the lower of the actual unit output or the dispatch signal MW. (Priority: Medium. First reported Q1, 2018. Status: Not adopted.)
- 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. (Priority: Medium. First reported Q1, 2018. Status: Not adopted.)
- 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 (Priority: Medium. New recommendation. Status: Not adopted.)

Section 5, Capacity Market

The MMU recognizes that PJM has implemented the Capacity Performance Construct to replace some of the existing core market rules and to address fundamental performance incentive issues. The MMU recognizes that the Capacity Performance Construct addresses many of the MMU's recommendations. The MMU's recommendations are based on the existing capacity market rules. The status is reported as adopted if the recommendation was included in FERC's order approving PJM's Capacity Performance filing.[14]

Definition of Capacity

- 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.[15] [16] (Priority: High. First reported 2013. Status: Not adopted.)
- The MMU recommends that DR providers be required to have a signed contract with specific customers for specific facilities for specific levels of DR at least six months prior to any capacity auction in which the DR is offered. (Priority: High. First reported 2016. Status: Not adopted.)

Market Design and Parameters

- The MMU recommends that the test for determining modeled Locational Deliverability Areas (LDAs) in RPM be redefined. A detailed reliability analysis of all at risk units should be included in the redefined model. (Priority: Medium. First reported 2013. Status: Not adopted.)
- The MMU recommends that the net revenue calculation used by PJM to calculate the net Cost of New Entry (CONE) VRR parameter reflect the actual flexibility of units in responding to price signals rather than using assumed fixed operating blocks that are not a result of actual unit limitations.[17] [18] The result of reflecting the actual flexibility is higher net revenues, which affect the parameters of the RPM demand curve and market outcomes. (Priority: High. First reported 2013. Status: Not adopted.)
- 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 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, there is no reason to have an add back mechanism. If EE remains on the supply side, the implementation of the EE add back mechanism should be modified to ensure that market clearing prices are not affected.

13 On September 7, 2018 PJM made a compliance filing for FERC Order No. 844 to publish unit specific uplift credits. The compliance filing has not been accepted by FERC. Absent acceptance from the FERC, PJM will not begin publishing data on unit specific uplift credits.

14 151 FERC ¶ 61,208 (2015).

15 See also Comments of the Independent Market Monitor for PJM, Docket No. ER14-503-000 (December 20, 2013).

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

17 See PJM Interconnection, L.L.C., Docket No. ER12-513-000 (December 1, 2011) ("Triennial Review").

18 See the *2017 State of the Market Report for PJM*, Volume 2, Section 7: Net Revenue.

(Priority: Medium. First reported 2016. Status: Not adopted.)

- The MMU recommends that PJM reduce the number of incremental auctions to a single incremental auction held three months prior to the start of the delivery year and reevaluate the triggers for holding conditional incremental auctions. (Priority: Medium. First reported 2013. Status: Not adopted.)
- The MMU recommends that PJM offer to sell back capacity in incremental auctions only at the BRA clearing price for the relevant delivery year. (Priority: Medium. First reported 2017. Status: Not adopted.)
- The MMU recommends changing the RPM solution method to explicitly incorporate the cost of make whole payments in the objective function. (Priority: Medium. First reported 2014. Status: Not adopted.)
- The MMU recommends that PJM clear the capacity market based on nodal capacity resource locations and the characteristics of the transmission system consistent with the actual electrical facts of the grid. 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. (Priority: Medium. First reported 2017. Status: Not adopted.)

Offer Caps, Offer Floors, and Must Offer

- The MMU recommends use of the Sustainable Market Rule (SMR) in order to protect competition in the capacity market from nonmarket revenues.[19] (Priority: High. First reported 2016. Status: Not adopted.)
- The MMU recommends that, as part of the MOPR unit specific standard of review, all projects be required to use the same basic modeling assumptions. That is the only way to ensure that projects compete on the basis of actual costs rather than on the basis of modeling assumptions.[20] (Priority: High. First reported 2013. Status: Not adopted.)
- The MMU recommends that modifications to existing resources not be treated as new resources for purposes of market power related offer caps or MOPR offer floors. (Priority: Low. First reported 2012. Status: Not adopted.)
- The MMU recommends that the RPM market power mitigation rule be modified to apply offer caps in all cases when the three pivotal supplier test is failed and the sell offer is greater than the offer cap. This will ensure that market power does not result in an increase in make whole payments. (Priority: Medium. First reported 2017. Status: Not adopted.)
- 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 reserve margins, and other assumptions consistent with the annual IRM study. (Priority: High. First reported 2017. Status: Not adopted.)
- 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. (Priority: High. First reported 2017. Status: Not adopted.)
- The MMU recommends that capacity market sellers be required to request the use of minimum MW quantities greater than 0 MW (inflexible sell offer

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

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

segments) and that the requests should only be permitted for defined physical reasons. (Priority: Medium. First reported Q3, 2018. Status: Not adopted.)

Performance Incentive Requirements of RPM

- The MMU recommends that a unit which is not capable of supplying energy consistent with its day-ahead offer reflect an appropriate outage. (Priority: Medium. First reported 2009. Status: Not adopted.)
- The MMU recommends that retroactive replacement transactions associated with a failure to perform during a PAH not be allowed and that, more generally, retroactive replacement capacity transactions not be permitted. (Priority: Medium. First reported 2016. Status: Not adopted.)
- The MMU recommends that there be an explicit requirement that capacity resource offers in the Day-Ahead Energy Market be competitive, where competitive is defined to be the short run marginal cost of the units. (Priority: Low. First reported 2013. Status: Not adopted.)

Capacity Imports and Exports

- 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. (Priority: High. First reported 2016. Status: Not adopted.)
- The MMU recommends that all costs incurred as a result of a pseudo tied unit be borne by the unit itself and included as appropriate in unit offers in the capacity market. (Priority: High. First reported 2016. Status: Not adopted.)
- 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. (Priority: Low. First reported 2010. Status: Partially adopted.)

Deactivations/Retirements

- The MMU recommends that the notification requirement for deactivations be extended from 90 days prior to the date of deactivation to 12 months prior to the date of deactivation and that PJM and the MMU be provided 60 days rather than 30 days to complete their reliability and market power analyses. (Priority: Low. First reported 2012. Status: Partially adopted.)
- The MMU recommends that 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. (Priority: Low. First reported 2010. Status: Not adopted.)
- 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. (Priority: Medium. First reported 2017. Status: Not adopted.)

Section 6, Demand Response

The MMU recognizes that PJM incorporated some of the recommendations related to demand response in the Capacity Performance filing. The status of each recommendation reflects the status at December 31, 2018.

- The MMU recommends, as a preferred alternative to including demand resources as supply in the capacity market, that demand resources be on the demand side of the markets, that customers be able to avoid capacity and energy charges by not using capacity and energy at their discretion, that customer payments be determined only by metered load, and that PJM forecasts immediately incorporate the impacts of demand side behavior. (Priority: High. First reported 2014. Status: Not adopted.)

- The MMU recommends that the option to specify a minimum dispatch price (strike price) for demand resources be eliminated and that participating resources receive the hourly real-time LMP less any generation component of their retail rate. (Priority: Medium. First reported 2010. Status: Not adopted.)
- The MMU recommends that the maximum offer for demand resources be the same as the maximum offer for generation resources. (Priority: Medium. First reported 2013. Status: Not adopted.)
- The MMU recommends that the demand resources be treated as economic resources, responding to economic price signals like other capacity resources. The MMU recommends that demand resources not be treated as emergency resources, not trigger a PJM emergency and not trigger a Performance Assessment Interval. (Priority: High. First reported 2012. Status: Not adopted.)
- The MMU recommends that the Emergency Program Energy Only option be eliminated because the opportunity to receive the appropriate energy market incentive is already provided in the economic program. (Priority: Low. First reported 2010. Status: Not adopted.)
- The MMU recommends that, if demand resources remain in the capacity market, a daily energy market must offer requirement apply to demand resources, comparable to the rule applicable to generation capacity resources.[21] (Priority: High. First reported 2013. Status: Not adopted.)
- The MMU recommends that demand resources be required to provide their nodal location, comparable to generation resources. (Priority: High. First reported 2011. Status: Not adopted.)
- The MMU recommends that PJM require nodal dispatch of demand resources with no advance notice required or, if nodal location is not required, subzonal dispatch of demand resources with no advance notice required. (Priority: High. First reported 2015. Status: Not adopted.)
- The MMU recommends that PJM not remove any defined subzones and maintain a public record of all created and removed subzones. (Priority: Low. First reported 2016. Status: Not adopted.)
- The MMU recommends that PJM eliminate the measurement of compliance across zones within a compliance aggregation area (CAA). The multiple zone approach is less locational than the zonal and subzonal approach and creates larger mismatches between the locational need for the resources and the actual response. (Priority: High. First reported 2015. Status: Not adopted.)
- The MMU recommends that measurement and verification methods for demand resources be modified to reflect compliance more accurately. (Priority: Medium. First reported 2009. Status: Not adopted.)
- The MMU recommends that compliance rules be revised to include submittal of all necessary hourly load data, and that negative values be included when calculating event compliance across hours and registrations. (Priority: Medium. First reported 2012. Status: Not adopted.)
- The MMU recommends that PJM adopt the ISO-NE five-minute metering requirements in order to ensure that dispatchers have the necessary information for reliability and that market payments to demand resources be calculated based on interval meter data at the site of the demand reductions.[22] (Priority: Medium. First reported 2013. Status: Not adopted.)
- 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. (Priority: Medium. First reported 2013. Status: Partially adopted.)
- The MMU recommends that load management testing be initiated by PJM with limited warning to CSPs in order to more accurately represent the conditions of an emergency event. (Priority: Low. First reported 2012. Status: Not adopted.)
- The MMU recommends that shutdown cost be defined as the cost to curtail load for a given period that does not vary with the measured reduction or,

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

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

for behind the meter generators, be the start cost defined in Manual 15 for generators. (Priority: Low. First reported 2012. Status: Not adopted.)

- The MMU recommends that the Net Benefits Test be eliminated and that demand response resources be paid LMP less any generation component of the applicable retail rate. (Priority: Low. First reported 2015. Status: Not adopted.)
- The MMU recommends that the tariff rules for demand response clarify that a resource and its CSP, if any, must notify PJM of material changes affecting the capability of the resource to perform as registered and must terminate or modify registrations that are no longer capable of responding to PJM dispatch directives at defined levels because load has been reduced or eliminated, as in the case of bankrupt and/or out of service facilities. (Priority: Medium. First reported 2015. Status: Not adopted.)
- The MMU recommends that there be only one demand response product in the capacity market, with an obligation to respond when called for any hour of the delivery year. (Priority: High. First reported 2011. Status: Partially adopted.[23])
- The MMU recommends that the lead times for demand resources be shortened to 30 minutes with an hour minimum dispatch for all resources. (Priority: Medium. First reported 2013. Status: Partially adopted.)
- The MMU recommends setting the baseline for measuring capacity compliance under winter compliance at the customers' PLC, similar to GLD, to avoid double counting. (Priority: High. First reported 2010. Status: Partially adopted.)
- The MMU recommends the Relative Root Mean Squared Test be required for all demand resources with a CBL. (Priority: Low. First reported 2017. Status: Partially adopted.)
- The MMU recommends that PRD be required to respond during a PAI to be consistent with all CP resources. (Priority: High. First reported 2017. Status: Not adopted.)
- The MMU recommends that the limits imposed on the pre-emergency and emergency demand response share of the Synchronized Reserve Market be eliminated. (Priority: Medium. New recommendation. Status: Not adopted.)
- The MMU recommends that 30 minute pre-emergency and emergency demand response be considered to be 30 minute reserves. (Priority: Medium. New recommendation. Status: Not adopted.)
- 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 with the existing lag. (Priority: Medium. New recommendation. Status: Not adopted.)

Section 7, Net Revenue

There are no recommendations in this section.

Section 8, 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. (Priority: Medium. First reported 2010. Status: Not adopted.)
- The MMU recommends that the Commission reconsider its disclaimer of jurisdiction over RECs markets because, given market changes since that decision, it is clear that RECs materially affect jurisdictional rates. (Priority: High. New recommendation. Status: Not adopted.)
- 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. (Priority: Medium. New recommendation. Status: Not adopted.)
- The MMU recommends that jurisdictions with a renewable portfolio standard make the price and quantity data on supply and demand more transparent. (Priority: Low. First reported Q2, 2018. Status: Not adopted.)

23 PJM's Capacity Performance design requires resources to respond when called for any hour of the delivery year.

Section 9, Interchange Transactions

- The MMU recommends that PJM implement rules to prevent sham scheduling. The MMU recommends that PJM apply after the fact market settlement adjustments to identified sham scheduling segments to ensure that market participants cannot benefit from sham scheduling. (Priority: High. First reported 2012. Status: Not adopted. Stakeholder process.)
- The MMU recommends that PJM implement a validation method for submitted transactions that would prohibit market participants from breaking transactions into smaller segments to defeat the interface pricing rule by concealing the true source or sink of the transaction. (Priority: Medium. First reported 2013. Status: Not adopted.)
- The MMU recommends that PJM implement a validation method for submitted transactions that would require market participants to submit transactions on paths that reflect the expected actual power flow in order to reduce unscheduled loop flows. (Priority: Medium. First reported 2013. Status: Not adopted.)
- The MMU recommends that PJM end the practice of maintaining outdated definitions of interface pricing points, eliminate the NIPSCO, Southeast and Southwest interface pricing points from the 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. (Priority: Medium. First reported 2013. Status: Not adopted.)
- The MMU recommends that PJM eliminate the IMO interface pricing point, and assign the transactions that originate or sink in the IESO balancing authority to the MISO interface pricing point. (Priority: Medium. First reported 2013. Status: Not adopted.)
- The MMU recommends that PJM monitor, and adjust as necessary, the weights applied to the components of the interfaces to ensure that the interface prices reflect ongoing changes in system conditions. The MMU also recommends that PJM review the mappings of external balancing authorities to individual interface pricing points to reflect changes to the impact of the external power source on PJM tie lines as a result of system topology changes. The MMU recommends that this review occur at least annually. (Priority: Low. First reported 2009. Status: Not adopted.)
- The MMU recommends that, in order to permit a complete analysis of loop flow, FERC and NERC ensure that the identified data are made available to market monitors as well as other industry entities determined appropriate by FERC. (Priority: Medium. First reported 2003. Status: Not adopted.)
- The MMU recommends that PJM explore an interchange optimization solution with its neighboring balancing authorities that would remove the need for market participants to schedule physical transactions across seams. Such a solution would include an optimized, but limited, joint dispatch approach that uses supply curves and treats seams between balancing authorities as constraints, similar to other constraints within an LMP market. (Priority: Medium. First reported 2014. Status: Not adopted.)
- The MMU recommends that PJM permit unlimited spot market imports as well as unlimited nonfirm point-to-point willing to pay congestion imports and exports at all PJM interfaces in order to improve the efficiency of the market. (Priority: Medium. First reported 2012. Status: Not adopted.)
- The MMU recommends that PJM immediately provide the required 12-month notice to Duke Energy Progress (DEP) to unilaterally terminate the Joint Operating Agreement. (Priority: Low. First reported 2013. Status: Not adopted.)
- The MMU recommends that PJMSettlement 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. (Priority: Low. First reported 2015. Status: Not adopted.)
- The MMU recommends that the emergency interchange cap be replaced with a market based solution. (Priority: Low. First reported 2015. Status: Not adopted.)

- The MMU recommends that the submission deadline for real-time dispatchable transactions be modified from 1800 on the day prior, to three hours prior to the requested start time, and that the minimum duration be modified from one hour to 15 minutes. These changes would give PJM a more flexible product that could be used to meet load in the most economic manner. (Priority: Medium. First reported 2014. Status: Partially adopted, 2015.)

Section 10, 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. (Priority: High. First reported 2012. Status: Not adopted. FERC rejected, pending rehearing request before FERC.[24])
- The MMU recommends that the lost opportunity cost in the ancillary services markets be calculated using the schedule on which the unit was scheduled to run in the energy market. (Priority: High. First reported 2010. Status: Not adopted.[25] FERC rejected, pending rehearing request before FERC.[26])
- The MMU recommends that the lost opportunity cost calculation used in the Regulation Market be based on the resource's dispatched energy offer schedule, not the lower of its price or cost offer schedule. (Priority: Medium. First reported 2010. Status: Not adopted. FERC rejected, pending rehearing request before FERC.[27])
- The MMU recommends that, to prevent gaming, there be a penalty enforced in the Regulation Market as a reduction in performance score and/or a forfeiture of revenues when resource owners elect to deassign assigned regulation resources within the hour. (Priority: Medium. First reported 2016. Status: Not adopted. FERC rejected, pending rehearing request before FERC.[28])
- The MMU recommends enhanced documentation of the implementation of the Regulation Market design. (Priority: Medium. First reported 2010. Status: Not adopted. FERC rejected, pending rehearing request before FERC.[29])
- 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. (Priority: Medium. First reported 2016. Status: Adopted, 2018.)
- The MMU recommends that PJM be required to save data elements necessary for verifying the performance of the Regulation Market. (Priority: Medium. First reported 2010. Status: Not adopted.)
- The MMU recommends that the $7.50 margin be eliminated from the definition of the cost of tier 2 synchronized reserve because it is a markup and not a cost. (Priority: Medium. First reported Q3, 2018. Status: Not adopted.)
- 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. (Priority: High. First reported 2013. Status: Not adopted.)
- The MMU recommends that the tier 2 synchronized reserve must offer requirement be enforced on a daily and hourly basis. The MMU recommends that PJM define a set of acceptable reasons why a unit can be made unavailable daily or hourly and require unit owners to select a reason in Markets Gateway whenever making a unit unavailable either daily or hourly or setting the offer MW to 0 MW. (Priority: Medium. First reported 2013. Status: Partially adopted.)
- 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.

24 FERC Docket No. ER18-87.

25 This recommendation was adopted by PJM for the Energy Market. Lost opportunity costs in the Energy Market are calculated using the schedule on which the unit was scheduled to run. In the Regulation Market, this recommendation has not been adopted, as the LOC continues to be calculated based on the lower of price or cost in the energy market offer.

26 FERC Docket No. ER18-87.

27 *Id.*

28 *Id.*

29 *Id.*

(Priority: Medium. First reported 2012. Status: Not adopted.)

- 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. (Priority: Medium. First reported Q3, 2018. Status: Not adopted.)
- The MMU recommends that aggregation not be permitted to offset unit specific penalties for failure to respond to a synchronized reserve event. (Priority: Medium. First reported Q3, 2018. Status: Not adopted.)
- The MMU recommends that PJM eliminate the use of Degree of Generator Performance (DGP) in the synchronized reserve market solution and improve the actual tier 1 estimate. If PJM continues to use DGP, DGP should be documented in PJM's manuals. (Priority: Medium. New recommendation. Status: Not adopted.)
- The MMU recommends that a reason code be attached to every hour in which PJM market operations adds additional DASR MW. (Priority: Medium. First reported 2015. Status: Not adopted.)
- The MMU recommends that PJM modify the DASR Market to ensure that all resources cleared incur a real-time performance obligation. (Priority: Low. First reported 2013. Status: Not adopted.)
- The MMU recommends that offers in the DASR Market be based on opportunity cost only in order to eliminate market power. (Priority: Low. First reported 2009. Modified, 2018. Status: Not adopted.)
- The MMU recommends that separate cost of service payments for reactive capability be eliminated and the cost of reactive capability be recovered in the capacity market. (Priority: Medium. First reported 2016. Status: Not adopted.)
- The MMU recommends that payments for reactive capability, if continued, be based on the 0.90 power factor that PJM has determined is necessary. (Priority: Medium. First reported Q3, 2018. Status: Not adopted.)
- 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. (Priority: Medium. New recommendation. Status: Not adopted.)
- The MMU recommends 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 the MTSL will be calculated for black start units sharing oil tanks. (Priority: Medium. First reported 2017. Status: Not adopted.)
- 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. (Priority: Low. First reported 2017. Status: Not adopted.)

Section 11, Congestion and Marginal Losses

There are no recommendations in this section.

Section 12, Planning

Generation Retirements

- The MMU recommends that the question of whether Capacity Injection Rights (CIRs) should persist after the retirement of a unit, or the conversion from CP to energy only status, be addressed. The rules need to ensure that incumbents cannot exploit control of CIRs to block or postpone entry of competitors.[30] (Priority: Low. First reported 2013. Status: Not adopted.)
- 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.

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

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

Generation Queue

- The MMU recommends that barriers to entry be addressed in a timely manner in order to help ensure that the capacity market will result in the entry of new capacity to meet the needs of PJM market participants and reflect the uncertainty and resultant risks in the cost of new entry used to establish the capacity market demand curve in RPM. (Priority: Low. First reported 2012. Status: Not adopted.)
- The MMU recommends improvements in queue management including that PJM establish a review process to ensure that projects are removed from the queue if they are not viable, as well as a process to allow commercially viable projects to advance in the queue ahead of projects which have failed to make progress, subject to rules to prevent gaming. (Priority: Medium. First reported 2013. Status: Partially adopted.)
- The MMU recommends continuing analysis of the study phase of PJM's transmission planning to reduce the need for postponements of study results, to decrease study completion times, and to improve the likelihood that a project at a given phase in the study process will successfully go into service. (Priority: Medium. First reported 2014. Status: Partially adopted.)
- The MMU recommends outsourcing interconnection studies to an independent party to avoid potential conflicts of interest. Currently, these studies are performed by incumbent transmission owners under PJM's direction. This creates potential conflicts of interest, particularly when transmission owners are vertically integrated and the owner of transmission also owns generation. (Priority: Low. First reported 2013. Status: Not adopted.)

Market Efficiency Process

- The MMU recommends that 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. (Priority: Medium. First reported Q3 2018. Status: Not adopted.)
- 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. (Priority: Medium. New recommendation. Status: Not adopted.)

Supplemental Transmission Projects

- 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. (Priority: Medium. First reported 2017. Status: Not adopted.)

Transmission Competition

- 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. (Priority: Medium. First reported 2015. Status: Not adopted.)
- The MMU recommends that PJM continue to incorporate the principle that the goal of transmission planning should be the incorporation of transmission investment decisions into market driven processes as much as possible. (Priority: Low. First reported 2001. Status: Not adopted.)
- The MMU recommends the creation of a mechanism to permit a direct comparison, or competition, between transmission and generation alternatives, including which alternative is less costly and who bears the risks associated with each alternative. (Priority: Low. First reported 2013. Status: Not adopted.)
- The MMU recommends that PJM establish fair terms of access to rights of way and property, such as at substations, in order to remove any barriers to entry and permit competition between incumbent transmission providers and merchant transmission providers in the RTEP. (Priority: Medium. First reported 2014. Status: Not adopted.)

- The MMU recommends that rules be implemented to permit competition to provide financing for transmission projects. This competition could reduce the cost of capital for transmission projects and significantly reduce total costs to customers. (Priority: Low. First reported 2013. Status: Not adopted.)
- The MMU recommends that rules be implemented to require that project cost caps on new transmission projects be part of the evaluation of competing projects. (Priority: Medium. First reported 2015. Status: Not adopted.)

Transmission Facility Outages

- 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.[31] (Priority: Medium. First reported 2015. Status: Not adopted.)
- The MMU recommends that PJM reevaluate all transmission outage tickets as on time or late as if they were new requests when an outage is rescheduled and apply the standard rules for late submissions to any such outages. (Priority: Low. First reported 2014. Status: Not adopted.)
- The MMU recommends that PJM draft a clear definition of the congestion analysis required for transmission outage requests to include in Manual 3 after appropriate review. (Priority: Low. First reported 2015. Status: Not adopted.)
- 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. (Priority: Low. First reported 2015. Status: Not adopted.)
- The MMU recommends that PJM not permit transmission owners to divide long duration outages into smaller segments to avoid complying with the requirements for long duration outages. (Priority: Low. First reported 2015. Status: Not adopted.)

Section 13, FTRs and ARRs

- The MMU recommends that the ARR/FTR design be modified to ensure that the rights to all congestion revenues are assigned to load. (Priority: High. First reported 2015. Status: Not adopted.)
- The MMU recommends that the Long Term FTR product be eliminated. (Priority: High. First reported Q3, 2018. Status: Not adopted.)
- 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. (Priority: High. First reported 2017. Status: Not adopted.)
- The MMU recommends that the 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. (Priority: High. First reported 2017. Status: Not adopted.)
- The MMU recommends that all FTR auction revenue be distributed to ARR holders monthly, regardless of FTR funding levels. (Priority: High. First reported 2015. Status: Not adopted.)
- The MMU recommends that, under the current FTR design, all congestion revenue in excess of FTR target allocations be distributed to ARR holders on a monthly basis. (Priority: High. First reported Q1, 2018. Status: Not adopted.)
- The MMU recommends that FTR auction revenues not be used to buy counter flow FTRs for the purpose of improving FTR payout ratios.[32] (Priority: High. First reported 2015. Status: Not adopted.)
- The MMU recommends that all historical generation to load paths be eliminated as a basis for allocating ARRs. (Priority: High. First reported 2015. Status: Partially adopted.)
- The MMU recommends that PJM eliminate portfolio netting to eliminate cross subsidies among FTR market participants. (Priority: High. First reported 2012. Status: Not adopted. Rejected by FERC.)
- The MMU recommends that PJM eliminate subsidies to counter flow FTRs by applying the payout ratio

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

32 See "PJM Manual 6: Financial Transmission Rights," Rev. 21 (Dec. 6, 2018) .

to counter flow FTRs in the same way the payout ratio is applied to prevailing flow FTRs. (Priority: High. First reported 2012. Status: Not adopted.)

- The MMU recommends that PJM eliminate geographic cross subsidies. (Priority: High. First reported 2013. Status: Not adopted.)
- The MMU recommends that PJM examine the mechanism by which self scheduled FTRs are allocated when load switching among LSEs occurs throughout the planning period. (Priority: Low. First reported 2011. Status: Not adopted.)
- The MMU recommends that PJM improve transmission outage modeling in the FTR auction models, including the use of probabilistic outage modeling. (Priority: Low. First reported 2013. Status: Not adopted.)
- The MMU recommends that PJM reduce FTR sales on paths with persistent overallocation of FTRs including clear rules for what defines persistent overallocation and how the reduction will be applied. (Priority: High. First reported 2013. Status: Partially adopted, 2014/2015 planning period.)
- The MMU recommends that PJM and its members continue to review the management of a defaulted member's FTR portfolio, including options other than immediate liquidation. (Priority: High. First reported Q2, 2018. Status: Not adopted.)
- The MMU recommends that PJM continue to evaluate the bilateral indemnification rules and any asymmetries they may create. (Priority: Low. New recommendation. Status: Not adopted.)
- The MMU recommends that PJM reexamine the source and sink node combinations available in the FTR market. (Priority: High. New recommendation. Status: Not adopted.)
- 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. (Priority: High. New recommendation. Status: Not adopted.)
- The MMU recommends that the direct customer request approach for creating and allocating IARR should be eliminated from PJM's tariff. (Priority: Low. New recommendation. Status: Not adopted.)

Adopted Recommendations

The following is the complete list of all MMU recommendations that have been adopted by PJM, including the priority, date of first report, date of last report, and the section in the State of the Market Report in which the recommendation was made.

Adopted 2018

- 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. (Priority: Medium. First reported 2016. Last reported 2018, Section 3, Energy Market.)
- The MMU recommends that units scheduled in the Day-Ahead Energy Market and not committed in real time be compensated for LOC incurred within an hour. (Priority: Medium. First reported 2013. Last reported Q3, 2018, Section 4, 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. (Priority: High. First reported 2013. Last reported 2018, Section 4, 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 the Manual 11 attachment C procedure with the implementation of hourly offers (ER16-372-000). (Priority: Medium. First reported 2016. Last reported 2018, Section 4, Energy Uplift.33)
- 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. (Priority: Medium. First reported 2016. Last reported Q3, 2018, Section 10, Ancillary Services.)

33 Although this recommendation has not been adopted exactly as recommended by the MMU, the implementation of hourly offers by PJM has effectively adopted this recommendation.

Adopted 2017

- The MMU recommends that PJM and MISO work together to align interface pricing definitions, using the same number of external buses and selecting buses in close proximity on either side of the border with comparable bus weights. (Priority: Medium. First reported 2012. Last reported 2018 Q3, Section 9, Interchange Transactions.)
- The MMU recommends that PJM apply the FTR forfeiture rule to up to congestion transactions consistent with the application of the FTR forfeiture rule to increment offers and decrement bids. (Priority: High. First reported 2013. Last reported 2018 Q3, Section 13, Financial Transmission and Auction Revenue Rights.)

Adopted 2016

- The MMU recommends that PJM report correct monthly payout ratios to reduce understatement of payout ratios on a monthly basis. (Priority: Low. First reported 2012. Last reported: 2018 Q3, Section 13, Financial Transmission and Auction Revenue Rights.)
- The MMU recommends that the single clearing price for synchronized reserves be determined based on the actual five minute LMP and actual LOC and not the forecast LMP. (Priority: Low. First reported 2010. Status: Adopted, 2016. Last reported: 2018 Q3, Section 10, Ancillary Service Markets)

Adopted 2015

- The MMU recommends that the lost opportunity cost in the energy market be calculated using the schedule on which the unit was scheduled to run in the energy market. (Priority: High. First reported 2009. Last reported: 2018 Q3 Section 4, Energy Uplift.)
- The MMU recommends including no load and startup costs as part of the total avoided costs in the calculation of lost opportunity cost credits paid to combustion turbines and diesels scheduled in the Day-Ahead Energy Market but not committed in real time. (Priority: Medium. First reported 2012. Last reported: 2018 Q3 Section 4, Energy Uplift.)
- The MMU recommends using the entire offer curve and not a single point on the offer curve to calculate energy lost opportunity cost. (Priority: Medium. First reported 2012. Last reported: 2018 Q3 Section 4, Energy Uplift.)
- The MMU recommends that all generation types face the same performance incentives. (Priority: High. First reported 2009. Last reported: 2012 Section 4, Capacity Market.)
- The existence of a capacity market that links payments for capacity to the level of unforced capacity and therefore to the forced outage rate creates an incentive to improve forced outage rates. The performance incentives in the RPM Capacity Market design need to be strengthened. (Priority: High. First reported 2009. Last reported: 2009 Section 5, Capacity Market.)
- The MMU recommends that the obligations of capacity resources be more clearly defined in the market rules. (Priority: High. First reported 2010. Last reported: 2011 Section 4, Capacity Market.)
- The MMU recommends that PJM eliminate all OMC outages from the calculation of forced outage rates used for any purpose in the PJM Capacity Market. (Priority: Medium. First reported 2013. Last reported: 2018 Q3 Section 5, Capacity Market.)
- The MMU recommends immediate elimination of lack of fuel as an acceptable basis for an OMC outage. (Priority: Medium. First reported 2012. Last reported: 2012 Section 4, Capacity Market.)
- PJM should scrutinize OMC outages for low Btu coal carefully. (Priority: Medium. First reported 2003. Last reported: 2009 Section 4, Capacity Market.)
- The MMU recommends that PJM eliminate the broad exception related to lack of gas during the winter period for single-fuel, natural gas-fired units. (Priority: Medium. First reported 2013. Last reported: 2018 Q3 Section 5, Capacity Market.)
- The MMU recommends that Generation Capacity Resources be paid on the basis of whether they produce energy when called upon during any of the hours defined as critical. One hundred percent of capacity market revenue should be at risk rather than only fifty percent. (Priority: High. First reported 2012. Last reported: 2018 Q3 Section 5, Capacity Market.)
- The MMU recommends elimination of the exception related to a unit that runs less than 50 hours during

the RPM peak period. (Priority: Low. First reported 2012. Last reported: 2012 Section 4 Capacity Market.)

- The MMU recommends that the use of the 2.5 percent demand adjustment (Short Term Resource Procurement Target) be terminated immediately. The 2.5 percent should be added back to the overall market demand curve. (Priority: Medium. First reported 2012. Last reported: 2018 Q3 Section 5 Capacity Market.)
- The MMU recommends that the definition of demand side resources be modified to ensure that such resources be fully substitutable for other generation capacity resources. Both the Limited and the Extended Summer DR products should be eliminated in order to ensure that the DR product has the same unlimited obligation to provide capacity year round as generation capacity resources. (Priority: High. First reported 2012. Last reported: 2018 Q3 Section 5 Capacity Market.)
- The MMU recommends that PJM increase the Capacity Resource Deficiency Charge, which is a penalty charge. (Priority: High. First reported 2013. Last reported: 2013 Section 5 Capacity Market.)
- The MMU recommends that all capacity imports have firm transmission to the PJM border prior to offering in an RPM auction. (Priority: High. First reported 2014. Last reported: 2018 Q3 Section 5, Capacity Market.)
- The MMU recommends that all capacity imports be required to be pseudo tied prior to the relevant Delivery Year in order to ensure that imports are as close to full substitutes for internal, physical capacity resources as possible. (Priority: High. First reported 2014. Last reported: 2017 Section 5, Capacity Market.)
- The MMU recommends that all resources importing capacity into PJM accept a must offer requirement. (Priority: High. First reported 2014. Last reported: 2018 Q3 Section 5, Capacity Market.)
- The MMU recommends capping the baseline for measuring compliance under GLD, for the limited summer product, at the customers' PLC. (Priority: High. First reported 2010. Last reported: 2018 Q3 Section 6, Demand Response.)
- Continued development of appropriate credit protections for transactions in PJM markets that are consistent with those available to participants in bilateral transactions. (Priority: Low. First reported 2002. Last reported: 2002 Section: Recommendations.)

Adopted 2014

- The MMU recommends that PJM require all generating units to identify the fuel type associated with each of their offered schedules. (Priority: Low. First reported 2014. Last reported: 2018 Q1 Section 3, Energy Market.)
- Pending elimination of these DR products, the MMU recommends that PJM procure the maximum amount of Annual and Extended Summer capacity resources available during an RPM auction, without impacting the clearing price. Currently, PJM procures a minimum level of Extended Summer and Annual Resources, but could procure additional MW of these superior products without a change in the clearing price. (Priority: Medium. First reported 2012. Last reported: 2012 Section 4, Capacity Market.)
- The MMU recommends that demand resources whose technology type (load drop method) is designated as "Other" explicitly record the technology type. (Priority: Low. First reported 2013. Last reported: 2018 Q3 Section 6, Demand Response.)
- The MMU recommends that the Enhanced energy Scheduler (EES) application be modified to require that transactions be scheduled for a constant MW level over the entire 45 minutes as soon as possible. This business rule is currently in the PJM Manuals, but is not being enforced. (Priority: Low. First reported 2009. Last reported: 2011 Section 8, Interchange Transactions.)
- The MMU recommends that the rules for compliance with calls to respond to actual spinning events be reevaluated. (Priority: Low. First reported 2011. Last reported: 2012 Section 9, Ancillary Service Markets.)
- The MMU recommends that no payments be made to tier 1 synchronized reserve resources if they are deselected in the PJM market solution. The MMU also recommends that documentation of the tier 1 synchronized reserve deselection process be published. (Priority: High. First reported 2014.

Status: Adopted, 2014. Last reported: 2018 Q3 Section 10, Ancillary Service Markets.)

Adopted 2013

- The MMU recommends that the notification requirement for deactivations be modified to include required notification of six to twelve months prior to an auction in which the unit will not be offered due to deactivation. The purpose of this deadline is to allow adequate time for potential Capacity Market Sellers to offer new capacity in the auction. (Priority: Low. First reported 2012. Last reported: 2012 Section 4, Capacity Market.)
- The MMU recommends modifying the evaluation criteria via a change to PJM's market software, to ensure that not willing to pay congestion transactions are not permitted to flow in the presence of congestion. (Priority: Low. First reported 2009. Last reported: 2009 Section 4, Interchange Transactions.)
- The MMU recommends that PJM modify the not willing to pay congestion product to address the issues of uncollected congestion charges. The MMU recommends charging market participants for any congestion incurred while such transactions are loaded, regardless of their election of transmission service, and restricting the use of not willing to pay congestion transactions to transactions at interfaces (wheeling transactions). (Priority: Low. First reported 2010. Last reported: 2011 Section 8, Interchange Transactions.)
- The MMU recommends that PJM, FERC, reliability authorities and state regulators reevaluate the way in which black start service is procured in order to ensure that procurement is done in a least cost manner for the entire PJM market. PJM should have responsibility to prepare the black start restoration plan for the region, with Members playing an advisory role. PJM should have the responsibility to procure required black start service on a least cost basis through a transparent process. (Priority: Low. First reported 2009. Last reported: 2011 Section 9, Ancillary Service Markets.)
- The MMU recommends that PJM document the reasons each time it changes the Tier 1 synchronized reserve transfer capability into the Mid-Atlantic subzone market because of the potential impacts on the market. (Priority: Low. First reported 2011. Last reported: 2011 Section 9, Ancillary Service Markets.)

Adopted 2012

- The MMU recommends that PJM should, on an expedited basis, request that the tariff be modified to permit allocation of day-ahead operating reserve charges consistent with the prior allocation of these charges in real time. This would be a short term solution to the issue created by shifting operating reserve charges to the Day-Ahead Energy Market and therefore changing the allocation of those charges. In addition, PJM should start a stakeholder process to consider the market design and cost allocation issues in detail and propose a permanent tariff change that results from the process. (Priority: High. First reported 2012. Last reported: 2012-Q3 Section 3, Operating Reserve.)
- The MMU recommends that the single clearing price for synchronized reserves be determined based on the actual five minute LMP and actual LOC and not the forecast LMP. (Priority: Low. First reported 2010. Last reported: 2018 Q3 Section 10, Ancillary Service Markets.)
- The MMU recommends that PJM conduct a detailed review of the Day-Ahead Market software in order to address the issue of occasional anomalous loss factors and their effect on the day-ahead market results. (Priority: Low. First reported 2011. Last reported: 2011 Section 10, Congestion and Marginal Losses.)
- The MMU recommends that the roles of PJM and the transmission owners in the decision making process to control for local contingencies be clarified, that PJM's role be strengthened and that the process be made transparent. (Priority: Low. First reported 2013. Last reported 2018 Q3, Section 3, Energy Market.)
- The MMU recommends the use of a single five minute clearing price based on actual five minute LMP and lost opportunity cost to improve the performance of the Regulation Market. (Priority: Medium. First reported 2010. Status: Adopted in 2012. Last reported 2018 Q3, Section 10, Ancillary Service Markets.)

Adopted 2011

- The MMU recommends eliminating internal source and sink bus designations for external energy transactions in the Day-Ahead and Real-Time Energy Markets. (Priority: Low. First reported 2010. Last reported: 2011 Section 8, Interchange Transactions.)
- The MMU continues to recommend the complete elimination of unsecured credit, over an appropriate transition period, based on the MMU's view of PJM's role in evaluating the credit worthiness of complex corporate entities and due to a concern about inappropriate shifts of risks and costs among PJM members. (Priority: Low. First reported 2009. Last reported: 2010 Section 8, Financial Transmission and Auction Revenue Rights.)

Adopted 2010

- Implementation of rules governing the definition of final prices to ensure certainty for market participants. (Priority: High. First reported 2008. Last reported: 2009 Section 1, Introduction.)
- The MMU recommends the implementation of improved cost-based data submission to permit better monitoring and better analysis of markets. (Priority: Medium. First reported 2002. Last reported: 2009 Section 1, Introduction.)

Adopted 2009

- Retention and application of enhancements to rules governing the payment of operating reserve credits to generators and the allocation of operating reserves charges among market participants that were implemented on December 1, 2008. The new operating reserve rules represent positive steps towards the goals of removing the ability to exercise market power and refining the allocation of operating reserves charges to better reflect causal factors. (Priority: High. First reported 2006. Last reported: 2007 Section 1, Introduction.)
- The MMU recommends that the RPM market structure, definitions and rules be modified to improve the efficiency of market prices and to ensure that market prices reflect the forward locational marginal value of capacity. (Priority: High. First reported 2006. Last reported: 2011 Section 4, Capacity.)
- Retention and application of the improved market power mitigation rules in the Regulation Market to prevent the exercise of market power in the Regulation Market while ensuring appropriate economic signals when investment is required and an efficient market mechanism. The PJM Regulation Market continues to be characterized by structural market power. PJM's application of targeted, flexible real-time, market power mitigation in the Regulation Market addresses only the hours in which structural market power exists and therefore provides an incentive for the continued development of competition. (Priority: High. First reported 2006. Last reported: 2009 Section 1, Introduction.)
- While it is reasonable to limit the authority of LSE/EDCs in the review of demand side settlements as the LSE/EDCs have economic incentives to deny settlements, LSE/EDCs should be able to initiate PJM settlement reviews. (Priority: Low. First reported 2009. Last reported: 2009 Section 2, Energy Market, Part 1.)
- The MMU recommends ways to further improve the Economic program by increasing the probability that payments are made only for economic and deliberate load reducing activities in response to price. (Priority: Low. First reported 2009. Last reported: 2009 Section 2, Energy Market, Part 1.)
  - The four steps in the normal operations review should be routinely applied to all registrations from the beginning of participation. This would include the ongoing evaluation of whether CBL accurately represents customer load for each customer; analysis of settlements to determine responsiveness to price and; required submission of detailed description of load reduction activities on specific days.
  - The definition of CBL should continue to be refined to ensure that it reflects the actual normal use of individual customers including normal daily and hourly fluctuations in usage and usage that is a function of measurable weather conditions. When used to determine compliance in Load Management testing for GLD customers, the CBL calculation should include adjustments for ambient conditions.
  - It is the MMU's recommendation that any settlement submitted with a consecutive 24 hour

period of CBL greater than metered load should initiate a CBL review by PJM and that a customer should be required to provide documentation of load reduction actions taken prior to acceptance of such settlements. Further, in order for PJM or the MMU to assess the accuracy of the CBL for a particular customer or for the Program in general, more hourly load data is required than is currently captured by PJM.

- If, for any settlement, the number of consecutive hours showing load reduction is beyond a reasonable window for load reducing actions in response to price, it should initiate a CBL review and warrant further substantiation from the customer and CSP.
- Load reduction in response to price must be clearly defined in the business rules and verified in a transparent daily settlement screen.

Adopted 2008

- Consistent application of local market power rules to all constraints. (Priority: High. First reported 2006. Last reported: 2007 Section 1, Introduction.)
- Retention and application of the improved local market power mitigation rules to prevent the exercise of local market power in the Energy Market while ensuring appropriate economic signals when investment is required. (Priority: Medium. First reported 2003. Last reported: 2009 Section 1, Introduction.)
- Consistent application of local market power rules to all units, including those currently exempt from offer capping. (Priority: High. First reported 2006. Last reported: 2007 Section 1, Introduction.)

Adopted 2006

- Modification of incentives in the capacity market to require all Load Serving Entities (LSEs) to meet their obligations to serve load on a longer-term basis and to require all capacity resources to be offered on a comparable longer term basis. (Priority: Medium. First reported 1999. Last reported: 2000 Section Summary.)
- Reevaluation of the criteria used to determine whether generating units qualify for capacity resource status. (Priority: Medium. First reported 1999. Last reported: 1999 Section Summary.)

Energy Market

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

The Market Monitoring Unit (MMU) analyzed measures of market structure, participant conduct and market performance in 2018, including market size, concentration, pivotal suppliers, offer behavior, and price.[1] The MMU concludes that the PJM energy market results were competitive in 2018.

Table 3-1 The energy market results were competitive

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

- The aggregate market structure was evaluated as partially competitive because the aggregate market power test based on pivotal suppliers indicates that the aggregate day-ahead market structure was not competitive on every day. The hourly HHI (Herfindahl-Hirschman Index) results indicate that the PJM energy market in 2018 was unconcentrated by FERC HHI standards in 94 percent of market hours and moderately concentrated in six percent of market hours. Average HHI was 840 with a minimum of 624 and a maximum of 1242 in 2018. The PJM energy market peaking segment of supply was highly concentrated. The fact that the average HHI is in the unconcentrated range and the maximum hourly HHI is in the moderately concentrated range does not mean that the aggregate market was competitive in all hours. As demonstrated for the day-ahead market, it is possible to have pivotal suppliers in the aggregate market even when the HHI level is not in the highly concentrated range. It is possible to have an exercise of market power even when the HHI level is not in the highly concentrated range. The number of pivotal suppliers in the energy market is a more precise measure of structural market power than the HHI. The HHI is not a definitive measure of structural market power.
- The local market structure was evaluated as not competitive due to the highly concentrated ownership of supply in local markets created by transmission constraints and local reliability issues. The results of the three pivotal supplier (TPS) test, used to test local market structure, indicate the existence of market power in local markets created by transmission constraints. The local market performance is competitive as a result of the application of the TPS test. While transmission constraints create the potential for the exercise of local market power, PJM's application of the three pivotal supplier test identified local market power and resulted in offer capping to force competitive offers, correcting for structural issues created by local transmission constraints. There are, however, identified issues with the application of market power mitigation to resources whose owners fail the TPS test that need to be addressed because unit owners can exercise market power even when they fail the TPS test.
- Participant behavior was evaluated as competitive because the analysis of markup shows that marginal units generally make offers at, or close to, their marginal costs in both Day-Ahead and Real-Time Energy Markets, although the behavior of some participants both routinely and during periods of high demand represents economic withholding and the markups of those participants affected LMP.
- Market performance was evaluated as competitive because market results in the energy market reflect the outcome of a competitive market, as PJM prices are set, on average, by marginal units operating at, or close to, their marginal costs in both Day-Ahead and Real-Time Energy Markets, although high markups for some marginal units did affect prices.
- Market design was evaluated as effective because the analysis shows that the PJM energy market

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

resulted in competitive market outcomes. In general, PJM's energy market design provides incentives for competitive behavior and results in competitive outcomes. In local markets, where market power is an issue, the market design identifies market power and causes the market to provide competitive market outcomes in most cases although issues with the implementation of market power mitigation and development of cost-based offers remain. The role of UTCs in the Day-Ahead Energy Market continues to cause concerns.

PJM markets are designed to promote competitive outcomes derived from the interaction of supply and demand in each of the PJM markets. Market design itself is the primary means of achieving and promoting competitive outcomes in PJM markets. One of the MMU's primary goals is to identify actual or potential market design flaws.[2] The approach to market power mitigation in PJM has focused on market designs that promote competition (a structural basis for competitive outcomes) and on limiting market power mitigation to instances where the market structure is not competitive and thus where market design alone cannot mitigate market power. In the PJM energy market, this occurs primarily in the case of local market power. When a transmission constraint creates the potential for local market power, PJM applies a structural test to determine if the local market is competitive, applies a behavioral test to determine if generator offers exceed competitive levels and applies a market performance test to determine if such generator offers would affect the market price.[3] There are, however, identified issues with the application of market power mitigation to resources whose owners fail the TPS test that can result in the exercise of local market power even when market power mitigation rules are applied. These issues need to be addressed. There are issues related to the definition of gas costs includable in energy offers that need to be addressed. There are issues related to the level of variable operating and maintenance expense includable in energy offers that need to be addressed. There are currently no market power mitigation rules in place that limit the ability to exercise market power when aggregate market conditions are tight and there are pivotal suppliers in the aggregate market. Aggregate market power needs to be addressed. Now that generators are allowed to modify offers hourly, market design must reflect appropriate incentives for competitive behavior, the application of local market power mitigation needs to be fixed, the definition of a competitive offer needs to be fixed, and aggregate market power mitigation rules need to be developed. The importance of these issues is amplified by the new rules permitting cost-based offers in excess of $1,000 per MWh.

2 OATT Attachment M (PJM Market Monitoring Plan).

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

Overview

Market Structure

- **Supply.** Supply includes physical generation, imports and virtual transactions. The maximum average on peak hourly offered real-time supply was 138,142 MWh for the winter and 150,674 MWh for the summer. In 2018, 12,826.2 MW of new resources were added and 5,522.7 MW were retired.

  PJM average real-time cleared generation in 2018 increased by 3.6 percent 2017, from 90,945 MWh to 94,236 MWh.

  PJM average day-ahead cleared supply in 2018, including INCs and up to congestion transactions, decreased by 12.3 percent from 2017, from 130,601 MWh to 114,556 MWh.

- **Aggregate Pivotal Suppliers.** The PJM energy market at times requires generation from pivotal suppliers to meet load, resulting in aggregate market power even when the HHI level indicates that the aggregate market is unconcentrated.

- **Generation Fuel Mix.** In 2018, coal units provided 28.6 percent, nuclear units 34.2 percent and natural gas units 30.6 percent of total generation. Compared to 2017, generation from coal units decreased 6.6 percent, generation from natural gas units increased 18.4 percent and generation from nuclear units decreased 0.5 percent.

- **Fuel Diversity.** In 2018, the fuel diversity of energy generation, measured by the fuel diversity index for energy (FDI_e), increased 0.9 percent over the FDI_e for 2017.

- **Marginal Resources.** In the PJM Real-Time Energy Market, in 2018, coal units were 27.3 percent and natural gas units were 63.3 percent of marginal resources. In 2017, coal units were 32.3 percent and natural gas units were 53.3 percent of marginal resources. Among the natural gas units that were marginal in 2018, nearly 85 percent were combined cycle units.

In the PJM Day-Ahead Energy Market, in 2018, up to congestion transactions were 62.3 percent, INCs were 9.8 percent, DECs were 16.9 percent, and generation resources were 10.9 percent of marginal resources. In 2017, up to congestion transactions were 79.9 percent, INCs were 5.5 percent, DECs were 10.2 percent, and generation resources were 4.3 percent of marginal resources.

- **Demand.** Demand includes physical load and exports and virtual transactions. The PJM accounting peak load in 2018 was 147,042 MWh in the HE 1700 on August 28, 2018, which was 4,656 MWh, 3.3 percent, higher than the PJM peak load for 2017, which was 142,387 MWh in the HE 1800 on July 19, 2017.

  PJM average real-time demand in 2018 increased by 4.3 percent from 2017, from 86,618 MWh to 90,307 MWh. PJM average day-ahead demand in 2018, including DECs and up to congestion transactions, decreased by 12.5 percent from 2017, from 125,792 MWh to 110,091 MWh.

- **Supply and Demand: Load and Spot Market.** Companies that serve load in PJM do so using a combination of self-supply, bilateral market purchases and spot market purchases. For 2018, 13.5 percent of real-time load was supplied by bilateral contracts, 28.8 percent by spot market purchases and 58.8 percent by self-supply. Compared to 2017, reliance on bilateral contracts decreased by 0.9 percentage points, reliance on spot market purchases increased by 1.3 percentage points and reliance on self-supply decreased by 0.1 percentage points.

Market Behavior

- **Offer Capping for Local Market Power.** PJM offer caps units when the local market structure is noncompetitive. Offer capping is an effective means of addressing local market power when the rules are designed and implemented properly. Offer capping levels have historically been low in PJM. In the Day-Ahead Energy Market, for units committed to provide energy for local constraint relief, offer-capped unit hours increased from 0.0 percent in 2017 to 0.1 percent in 2018. In the Real-Time Energy Market, for units committed to provide energy for local constraint relief, offer-capped unit hours increased from 0.3 percent in 2017 to 0.9 percent in 2018. While overall offer capping levels have been low, there are a significant number of units with persistent structural local market power that would have a significant impact on prices in the absence of local market power mitigation.

  In 2018, 14 control zones experienced congestion resulting from one or more constraints binding for 100 or more hours. The analysis of the application of the TPS test to local markets demonstrates that it is working successfully to identify pivotal owners when the market structure is noncompetitive and to ensure that owners are not subject to offer capping when the market structure is competitive. There are, however, identified issues with the application of market power mitigation to resources whose owners fail the TPS test that can result in the exercise of local market power. These issues need to be addressed.

- **Offer Capping for Reliability.** PJM also offer caps units that are committed for reliability reasons, including for reactive support. In the Day-Ahead Energy Market, for units committed for reliability reasons, offer-capped unit hours remained at 0.1 percent in 2017 and 2018. In the Real-Time Energy Market, for units committed for reliability reasons, offer-capped unit hours remained at 0.1 percent in 2017 and 2018.

- **Markup Index.** The markup index is a summary measure of participant offer behavior for individual marginal units. In 2018, in the PJM Real-Time Energy Market, 88.1 percent of marginal units had offer prices less than $50 per MWh. The average dollar markup of units with offer prices less than $25 was negative (-$0.44 per MWh) when using unadjusted cost-based offers. The average dollar markup of units with offer prices between $25 and $50 was positive ($1.91 per MWh) when using unadjusted cost-based offers. Negative markup means the unit is offering to run at a price less than its cost-based offer, demonstrating a revealed short run marginal cost that is less than the allowable cost-based offer under the PJM market rules. Some marginal units did have substantial markups. Using the unadjusted cost-based offers, the highest markup for any marginal unit in 2018 was more than $500 per MWh while the highest markup in 2017 was more than $700 per MWh. During the period of cold weather and high demand in January, several units in the PJM market were offered with high markups.

In 2018, in the PJM Day-Ahead Energy Market, 95.5 percent of marginal generating units had offer prices less than $50 per MWh. The average dollar markup of units with offer prices less than $25 was positive ($0.27 per MWh) when using unadjusted cost-based offers. The average dollar markup of units with offer prices between $25 and $50 was positive ($3.21 per MWh) when using unadjusted cost-based offers. Using the unadjusted cost-based offers, the highest markup for any marginal unit in 2018 was $200 per MWh, while the highest markup in 2017 was $85 per MWh.

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

  The markup behavior shown in the markup frequency distributions also shows that a substantial number of units were offered with high markups, consistent with the exercise of market power. Markup for gas fired units increased in 2018.

- **Frequently Mitigated Units (FMU) and Associated Units (AU).** A new FMU rule became effective November 1, 2014, limiting the availability of FMU adders to units with net revenues less than unit going forward costs. The number of units that were eligible for an FMU or AU adder declined from an average of 70 units during the first 11 months of 2014, to zero since December 2014.

- **Virtual Offers and Bids.** Any market participant in the PJM Day-Ahead Energy Market can use increment offers, decrement bids, up to congestion transactions, import transactions and export transactions as financial instruments that do not require physical generation or load. In 2018, the average hourly increment offers submitted and cleared MW decreased by 27.5 percent and 41.3 percent, from 7,968 MW and 4,562 MW in 2017 to 5,776 MW and 2,676 MW in 2018. The average hourly decrement bids submitted and cleared MW decreased by 14.2 percent and 28.0 percent, from 7,874 MW and 4,035 MW in 2017 to 6,753 MW and 2,906 MW in 2018. The average hourly up to congestion submitted and cleared MW decreased by 57.3 percent and 48.7 percent, from 137,419 MW and 34,387 MW in 2017 to 58,650 MW and 17,624 MW in 2018.

- **Generator Offers.** Generator offers are categorized as dispatchable and self scheduled. Units which are available for economic dispatch are dispatchable. Units which are self scheduled to generate fixed output are categorized as self scheduled. Units which are self scheduled at their economic minimum and are available for economic dispatch up to their economic maximum are categorized as self scheduled and dispatchable. Of all generator offers by MW in 2018, 25.4 percent were offered as available for economic dispatch, 31.3 percent were offered at their economic minimum, 4.5 percent were offered as emergency dispatch, 16.2 percent were offered as self scheduled, and 21.5 percent were offered as self scheduled and dispatchable.

Market Performance

- **Prices.** PJM LMPs are a direct measure of market performance. Price level is a good, general indicator of market performance, although the number of factors influencing the overall level of prices means it must be analyzed carefully. Among other things, overall average prices reflect changes in supply and demand, generation fuel mix, the cost of fuel, emissions related expenses, markup and local price differences caused by congestion. PJM also may administratively set prices with the creation of closed loop interfaces related to demand side resources or reactive power, the application of transmission penalty factors, or the application of price setting logic.

  PJM real-time energy market prices increased in 2018 compared to 2017. The load-weighted, average real-time LMP was 23.4 percent higher in 2018 than in 2017, $38.24 per MWh versus $30.99 per MWh.

  PJM day-ahead energy market prices increased in 2018 compared to 2017. The load-weighted, average day-ahead LMP was 23.1 percent higher in 2018 than in 2017, $37.97 per MWh versus $30.85 per MWh.

- **Components of LMP.** In the PJM Real-Time Energy Market, in 2018, 19.4 percent of the load-weighted LMP was the result of coal costs, 42.4 percent was the result of gas costs and 0.66 percent was the result of the cost of emission allowances.

  In the PJM Day-Ahead Energy Market, in 2018, 28.4 percent of the load-weighted LMP was the result of DEC bids, 19.6 percent was the result of gas costs, 18.5 percent was the result of INC offers, 16.2 percent was the result of coal costs, and 2.6 percent was the result of up to congestion transaction offers.

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

  In the PJM Real-Time Energy Market in 2018, the unadjusted markup component of LMP was $4.56 per MWh or 11.9 percent of the PJM load-weighted, average LMP. January had the highest unadjusted off peak markup component, $11.65 per MWh, or 13.28 percent of the real-time, off peak hour load-weighted, average LMP. There were 51 hours in 2018 where the positive markup contribution to the PJM system wide, load-weighted, average LMP exceeded $80.00 per MWh. During the period of cold weather and high demand in January, some units in the PJM market were offered with high markups.

  In the PJM Day-Ahead Energy Market, INCs, DECs and UTCs have zero markups. In 2018, the unadjusted markup component of LMP resulting from generation resources was $1.22 per MWh or 3.2 percent of the PJM day-ahead load-weighted average LMP. January had the highest unadjusted peak markup component, $4.21 per MWh.

  Participant behavior was evaluated as competitive because the analysis of markup shows that marginal units generally make offers at, or close to, their marginal costs in both the Day-Ahead and Real-Time Energy Markets, although the behavior of some participants represents economic withholding.

- **Price Convergence.** Hourly and daily price differences between the Day-Ahead and Real-Time Energy Markets fluctuate continuously and substantially from positive to negative. The difference between the average day-ahead and real-time prices was -$0.06 per MWh in 2017 and $0.06 per MWh in 2018. The difference between average day-ahead and real-time prices, by itself, is not a measure of the competitiveness or effectiveness of the Day-Ahead Energy Market.

Scarcity

- There were three intervals with five minute shortage pricing on two days in 2018. On August 31, 2018, for two intervals at 0935 EPT and 0940 EPT, synchronized reserves for the RTO Zone and MAD Subzone were less than the extended synchronized reserve requirements. On September 30, 2018, for one interval at 1135 EPT, synchronized reserves for the RTO Zone and MAD Subzone were less than the extended synchronized reserve requirements.

- There were 3,776 five minute intervals, or 3.6 percent of all five minute intervals in 2018 for which at least one solved SCED case showed a shortage of reserves, and 1,865 five minute intervals, or 1.8 percent of all five minute intervals in 2018 for which more than one solved SCED case showed a shortage of reserves. PJM operators used only three RT SCED cases that showed a shortage of reserves in LPC to calculate real-time LMPs and ancillary service prices.

- On May 29, 2018, there were six Performance Assessment Intervals (PAIs) triggered in the Edison area of the AEP Zone due to a localized load shed event. On July 18, 2018, there were 18 PAIs triggered in the Lonesome Pine area on the border of Virginia and West Virginia in the AEP Zone due to a localized load shed event to control for voltage violations. These PAIs did not trigger shortage pricing since reserve requirements in PJM are only set at the RTO Zone and MAD Subzone levels, and not at locational levels smaller than the MAD Subzone.

Recommendations

Market Power

- The MMU recommends that the market rules 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. (Priority: Medium. First reported 2009. Status: Not adopted.)

- The MMU recommends that PJM require that all fuel cost policies be algorithmic, verifiable, and systematic, and accurately reflect short run marginal costs. (Priority: Medium. First reported 2016. Status: Not adopted.)
- The MMU recommends that the 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 as the basis for Fuel Cost Policies but should not be required. (Priority: Low. First reported Q1, 2018. Status: Not adopted.)
- 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. (Priority: Low. First reported Q1, 2018. Status: Not adopted.)
- 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. (Priority: Medium. First reported 2016. Status: Not adopted.)
- The MMU recommends removal of all use of FERC System of Accounts in the Cost Development Guidelines. (Priority: Medium. First reported 2016. Status: Not adopted.)
- The MMU recommends the removal of all use of cyclic starting and peaking factors from the Cost Development Guidelines. (Priority: Medium. First reported 2016. Status: Not adopted.)
- The MMU recommends the removal of all labor costs from the Cost Development Guidelines. (Priority: Medium. First reported 2016. Status: Not adopted.)
- 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. (Priority: Medium. First reported 2016. Status: Not adopted.)
- The MMU recommends the removal of nuclear fuel and nonfuel operations and maintenance costs that are not short run marginal costs from the Cost Development Guidelines. (Priority: Medium. First reported 2016. Status: Not adopted.)
- The MMU recommends revising the pumped hydro fuel cost calculation to include day-ahead and real-time power purchases. (Priority: Low. First reported 2016. Status: Not adopted.)
- 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. (Priority: Medium. First reported 2016. Status: Adopted, 2018.)
- The MMU recommends removing the catastrophic designation for force majeure fuel supply limitations in Schedule 2. (Priority: Medium. First reported 2016. Status: Not adopted.)
- The MMU recommends that the rules governing the application of the TPS test be clarified and documented. The TPS test application in the Day-Ahead Energy Market is not documented. (Priority: High. First reported 2015. Status: Partially adopted.)
- The MMU recommends that PJM require every market participant to make available at least one cost schedule based on the same hourly fuel type(s) and parameters at least as flexible as their offered price schedule. (Priority: Medium. First reported 2015. Status: Not adopted.)
- The MMU recommends, in order to ensure effective market power mitigation when the TPS test is failed, that markup be constant across the full MWh range of price and cost-based offers. (Priority: High. First reported 2015. Status: Not adopted.)
- 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. (Priority: High. First reported 2015. Status: Not adopted.)

- The MMU recommends that PJM retain the $1,000 per MWh offer cap in the PJM energy market except when cost-based offers exceed $1,000 per MWh, and retain other existing rules that limit incentives to exercise market power. (Priority: High. First reported 1999. Status: Partially adopted, 1999, 2017.)
- The MMU recommends the elimination of FMU and AU adders. FMU and AU adders no longer serve the purpose for which they were created and interfere with the efficient operation of PJM markets. (Priority: Medium. First reported 2012. Status: Partially adopted, 2014.)
- 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.[4] (Priority: Medium. First reported 2012. Status: Not adopted.)

Capacity Performance Resources

- 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. (Priority: Medium. First reported 2015. Status: Not adopted.)
- The MMU recommends that the parameters which determine nonperformance charges and the amounts of uplift payments should reflect the flexibility goals of the capacity 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. (Priority: Medium. First reported 2015. Status: Partially adopted.)
- The MMU recommends that PJM not allow nuclear generators which do not respond to prices or which only respond to manual instructions from the dispatcher to set the LMPs in the real-time market. (Priority: Low. First reported 2016. Status: Not adopted.)
- The MMU recommends that PJM document how LMPs are calculated when demand response is marginal. (Priority: Low. First reported 2014. Status: Not Adopted.)
- The MMU recommends that PJM not 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. (Priority: Medium. First reported Q3, 2018. Status: Not adopted.)
- The MMU recommends that PJM clearly define the business rules that apply to the unit specific parameter adjustment process, including PJM's implementation of the tariff rules in the PJM manuals to ensure market sellers know the requirements for their resources. (Priority: Low. First reported Q3, 2018. Status: Not adopted.)
- The MMU recommends that PJM update the tariff to clarify that all generation resources are subject to unit specific parameter limits on their cost-based offers using the same standard and process as capacity performance capacity resources. (Priority: Medium. New recommendation. Status: Not adopted.)
- 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. (Priority: Medium. New recommendation. Status: Not adopted.)

Accurate System Modeling

- The MMU recommends that PJM explicitly state its policy on the use of transmission penalty factors including: the level of the penalty factors; the triggers for the use of the penalty factors; the

4 This recommendation was accepted by PJM and filed with FERC in 2014 as part of the capacity performance updates to the RPM. See Schedule 1, Section 1.10.1A(d), Revisions to the PJM Open Access Transmission Tariff and PJM Operating Agreement (Marked/Redline Format), EL15-29-000 (December 12, 2014). FERC rejected the proposed change. See 151 FERC ¶ 61,208 at P 476 (2015).

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. (Priority: Medium. First reported 2015. Status: Partially adopted.)

- The MMU recommends that PJM routinely review all transmission facility ratings and any changes to those ratings to ensure that the normal, emergency and load dump ratings used in modeling the transmission system are accurate and reflect standard ratings practice. (Priority: Low. First reported 2013. Status: Partially adopted.)
- The MMU recommends that PJM update the outage impact studies, the reliability analyses used in RPM for capacity deliverability, and the reliability analyses used in RTEP for transmission upgrades to be consistent with the more conservative emergency operations (post contingency load dump limit exceedance analysis) in the energy market that were implemented in June 2013. (Priority: Low. First reported 2013. Status: Not adopted.)
- The MMU recommends that PJM include in the tariff or appropriate manual an explanation of the initial creation of hubs, the process for modifying hub definitions and a description of how hub definitions have changed.[5] [6] (Priority: Low. First reported 2013. Status: Not adopted.)
- The MMU recommends that all buses with a net withdrawal be treated as load for purposes of calculating load and load-weighted LMP. 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. (Priority: Low. First reported 2013. Status: Not adopted.)
- The MMU recommends that PJM identify and collect data on available behind the meter generation resources, including nodal location information and relevant operating parameters. (Priority: Low. First reported 2013. Status: Partially adopted.)
- The MMU recommends that PJM increase the interaction of outage and operational restrictions data submitted by Market Participants via eDART/eGADs and offer data submitted via Markets Gateway. (Priority: Low. First reported 2017. Status: Not adopted.)

Transparency

- 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. (Priority: Medium. First reported 2015. Status: Partially adopted.)
- The MMU recommends that PJM continue to enhance its posting of market data to promote market efficiency. (Priority: Medium. First reported 2005. Status: Partially adopted.)
- 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. (Priority: High. New recommendation. Status: Not adopted.)

Conclusion

The MMU analyzed key elements of PJM energy market structure, participant conduct and market performance in 2018, including aggregate supply and demand, concentration ratios, aggregate pivotal supplier results, local three pivotal supplier test results, offer capping, participation in demand response programs, loads and prices.

PJM average real-time cleared generation increased by 3,292 MWh, 3.6 percent, and peak load increased by 4,656 MWh, 3.3 percent, in 2018 compared to 2017. The relationship between supply and demand, regardless of the specific market, balanced by market concentration and the extent of pivotal suppliers, is referred to as the supply-demand fundamentals or economic fundamentals. The market structure of the PJM aggregate energy market is partially competitive because aggregate market power

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

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

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

The three pivotal supplier test is applied by PJM on an ongoing basis for local energy markets in order to determine whether offer capping is required for transmission constraints.[7] However, there are some issues with the application of market power mitigation in the Day-Ahead Energy Market and the Real-Time Energy Market when market sellers fail the TPS test. These issues can be resolved by simple rule changes.

The enforcement of market power mitigation rules is undermined if the definition of a competitive offer is not correct. A competitive offer is equal to short run marginal costs. The significance of competition metrics like markup is also undermined if the definition of a competitive offer is not correct. The definition of a competitive offer, as interpreted by PJM, is not currently correct. Some unit owners include costs that are not short run marginal costs in offers, including maintenance costs. This issue can be resolved by simple rule changes to incorporate a clear and accurate definition of short run marginal costs.

Prices are a key outcome of markets. Prices vary across hours, days and years for multiple reasons. Price is an indicator of the level of competition in a market although individual prices are not always easy to interpret. In a competitive market, prices are directly related to the marginal cost to serve load in each market interval. The pattern of prices within days and across months and years illustrates how prices are directly related to supply and demand conditions and thus also illustrates the potential significance of the impact of the price elasticity of demand on prices. Energy market results in 2018 generally reflected supply-demand fundamentals, although the behavior of some participants both routinely and during high demand periods represents economic withholding. Economic withholding is the ability to increase markups substantially in tight market conditions. There are additional issues in the energy market including the uncertainties about the pricing and availability of natural gas, the way that generation owners incorporate natural gas costs in offers, and the lack of adequate incentives for unit owners to take all necessary actions to acquire fuel and operate rather than economically withhold or physically withhold.

Prices in PJM are not too low. There is no evidence to support the need for a significant change to the calculation of LMP. The underlying problem that fast start pricing and PJM's reserve pricing approach are attempting to address is actually scarcity pricing, including the impact of operator actions on the definition of scarcity. Prices do not reflect market conditions when the market is tight. Rather than undercutting the basic LMP logic that is core to market efficiency, it would make more sense to directly address scarcity pricing, operator actions and the design of reserve markets. Targeted increases to the demand for reserves when the market is tight would address price formation in the energy market.

When the real-time security constrained economic dispatch (RT SCED) solution does indicate a shortage of reserves, it should be used in calculating real-time prices. There are significant issues with operator discretion and reluctance to approve RT SCED cases indicating shortage of reserves, and in using these cases to calculate prices. While it is appropriate for operators to ensure that cases that use erroneous inputs are not approved and not allowed to set prices, it is essential that operator discretion not extend beyond what is necessary and that operator discretion not prevent shortage pricing when there are shortage conditions. There are also issues with the alignment of SCED cases used for resource

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

dispatch and the SCED cases used to calculate real-time prices. PJM should fix its current operating practices and ensure transparency regarding approval of SCED cases for resource dispatch and pricing so that market participants can have confidence in the market design to produce accurate and efficient price signals. These issues are even more critical now that PJM settles real-time energy transactions on a five minute basis.

The objective of efficient short run price signals is to minimize system production costs, not to minimize uplift. Repricing the market to reflect commitment costs would create a tradeoff between minimizing production costs and reduction of uplift. The tradeoff would exist because when commitment costs are included in prices, the price signal no longer equals the short run marginal cost and therefore no longer provides the correct signal for efficient behavior for market participants making decisions on the margin, whether resources, load, interchange transactions, or virtual traders. This tradeoff would be created by PJM's fast start pricing proposal and in a much more extensive form by PJM's convex hull pricing proposal and reserve pricing proposal.

The fast start pricing and convex hull solutions would undercut LMP logic rather than directly addressing the underlying issues. The solution is not to accept that the inflexible CT should be paid or set price-based on its commitment costs rather than its short run marginal costs. The question of why units make inflexible offers should be addressed directly. Are units inflexible because they are old and inefficient, because owners have not invested in increased flexibility or because they serve as a mechanism for the exercise of market power? The question of why this unit was built, whether it was built under cost of service regulation and whether it is efficient to retain the unit should be answered directly. The question of how to provide market incentives for investment in flexible units and for investment in increased flexibility of existing units should be addressed directly. The question of whether inflexible units should be paid uplift at all should be addressed directly. Marginal cost pricing without paying excess uplift to inflexible units would create incentives for market participants to provide flexible solutions including replacing inefficient units with flexible, efficient units.

With or without a capacity market, energy market design must permit scarcity pricing when such pricing is consistent with market conditions and constrained by reasonable rules to ensure that market power is not exercised. Scarcity pricing can serve two functions in wholesale power markets: revenue adequacy and price signals. Scarcity pricing for revenue adequacy is not required in PJM. Scarcity pricing for price signals that reflect market conditions during periods of scarcity is required in PJM. Scarcity pricing is also part of an appropriate incentive structure facing both load and generation owners in a working wholesale electric power market design. Scarcity pricing must be designed to ensure that market prices reflect actual market conditions, that scarcity pricing occurs with transparent triggers based on measured reserve levels and transparent prices, that scarcity pricing only occurs when scarcity exists, and that there are strong incentives for competitive behavior and strong disincentives to exercise market power. Such administrative scarcity pricing is a key link between energy and capacity markets.

The PJM Capacity Market is explicitly designed to provide revenue adequacy and the resultant reliability. However, the explicit balancing mechanism that included net revenues directly in unit offers in the prior capacity market design is not present in the Capacity Performance design. The nature of a direct and explicit energy pricing net revenue true up mechanism in the capacity market should be addressed if energy revenues are expected to increase as a result of scarcity events, as a result of increased demand for reserves, or as a result of PJM's inappropriate proposals related to fast start pricing and the inclusion of maintenance expenses as short run marginal costs. The true up mechanism must address both cleared auctions and subsequent auctions. There are also significant issues with PJM's scarcity pricing rules, including the absence of a clear trigger based on measured reserve levels (the current triggers are based on estimated reserves) and the lack of adequate locational scarcity pricing options.

The overall energy market results support the conclusion that energy prices in PJM are set, generally, by marginal units operating at, or close to, their marginal costs, although this was not always the case in 2018 or prior years. This is evidence of generally competitive behavior and competitive market outcomes, although the behavior of some participants represents economic withholding.

Markups were higher in 2018, especially during the cold weather in January. Given the structure of the energy market which can permit the exercise of aggregate market power, the change in some participants' behavior is a source of concern in the energy market and provides a reason to use correctly defined short run marginal cost as the sole basis for cost-based offers and a reason for implementing an aggregate market power test. The MMU concludes that the PJM energy market results were competitive in 2018.

Market Structure

Market Concentration

Analysis of supply curve segments of the PJM energy market in 2018 indicates low concentration in the base load segment and moderate concentration in the intermediate segment, but high concentration in the peaking segment.[8] High concentration levels, particularly in the peaking segment, increase the probability that a generation owner will be pivotal in the aggregate market. The fact that the average HHI is in the unconcentrated range and the maximum hourly HHI is in the moderately concentrated range does not mean that the aggregate market was competitive in all hours. It is possible to have pivotal suppliers in the aggregate market even when the HHI level does not indicate a highly concentrated market structure. It is possible to have an exercise of market power even when the HHI level does not indicate a highly concentrated market structure.

When transmission constraints exist, local markets are created with ownership that is typically significantly more concentrated than the overall energy market. PJM offer capping rules that limit the exercise of local market power were generally effective in preventing the exercise of market power in 2018, although there are issues with the application of market power mitigation for resources whose owners fail the TPS test that permit local market power to be exercised even when mitigation rules are applied. These issues include the lack of a method for consistently determining the cheaper of the cost and price schedules, and the lack of rules requiring that cost-based offers equal short run marginal costs.

The concentration ratio used here is the Herfindahl-Hirschman Index (HHI), calculated by summing the squares of the market shares of all firms in a market. Hourly PJM energy market HHIs were calculated based on the real-time energy output of generators, adjusted for hourly net imports by owner (Table 3-2).

In theory, the HHI provides insight into the relationship between market structure, behavior, and performance. In the case where participants compete by producing output at constant, but potentially different, marginal costs, the HHI is directly proportional to the expected average price cost markup in the market:[9]

$$\frac{HHI}{\varepsilon} = \frac{P - MC}{P}$$

where ε is the absolute value of the price elasticity of demand, *P* is the market price, and *MC* is the average marginal cost of production. The left side of the equation quantifies market structure, and the right side of the equation measures market performance. The assumed participant behavior is profit maximization. If HHI is very low, implying a more competitive market, prices converge to marginal cost, the competitive market outcome. But even a low HHI may result in substantial markup with a low price elasticity of demand. If HHI is very high, meaning competition is lacking, prices approach the monopoly level. Price elasticity of demand (ε) determines the degree to which suppliers with market power can impose higher prices on customers.

The HHI may not accurately capture market power issues in situations where, for example, there is moderate concentration in all on line resources but there is a high level of concentration in resources needed to meet increases in load. The HHIs for supply curve segments is an indication of such issues with the ownership of incremental resources. An aggregate pivotal supplier test is required to accurately measure the ability of incremental resources to exercise market power when load is high, for example.

Hourly HHIs were also calculated for baseload, intermediate and peaking segments of generation supply. Hourly energy market HHIs by supply curve segment were calculated based on hourly energy market shares, unadjusted for imports.

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

9 *See* Tirole, Jean. *The Theory of Industrial Organization*, MIT (1988), Chapter 5: Short-Run Price Competition.

The “Merger Policy Statement” of FERC states that a market can be broadly characterized as:

- **Unconcentrated.** Market HHI below 1000, equivalent to 10 firms with equal market shares;
- **Moderately Concentrated.** Market HHI between 1000 and 1800; and
- **Highly Concentrated.** Market HHI greater than 1800, equivalent to between five and six firms with equal market shares.[10]

The PJM energy market HHIs and the FERC concentration cutoffs may understate the degree of market power because, in the absence of aggregate market power mitigation, even the unconcentrated HHI level would imply substantial markups due to the low short run price elasticity of demand. For example, research estimates find short run demand elasticity ranging from -0.2 to -0.4.[11] These elasticities imply, for example, an average markup ranging from 25 to 50 percent at the unconcentrated to moderately concentrated threshold HHI of 1000:[12]

$$\frac{HHI}{\varepsilon} = \frac{0.1}{0.2} = \frac{P - MC}{P} = 50\%$$

With marginal costs of $33 per MWh and an average HHI of 840 in 2018, average PJM prices theoretically range from $42 to $57 per MWh, exceeding marginal costs as a result of the exercise of market power. Actual prices, averaging $38.24 per MWh, and markups, at 12 percent, are lower than the theoretical range, supporting the MMU’s competitive assessment of the market. However, markup is not zero. In some hours, markup and prices reach levels that reflect the exercise of market power.

PJM HHI Results

Calculations for hourly HHI indicate that by FERC standards, the PJM energy market during 2018 was unconcentrated (Table 3-2).

Table 3-2 Hourly energy market HHI: 2017 and 2018[13]

	Hourly Market HHI (2017)	Hourly Market HHI (2018)
Average	919	840
Minimum	696	624
Maximum	1205	1242
Highest market share (One hour)	27%	27%
Average of the highest hourly market share	19%	19%
# Hours	8,760	8,760
# Hours HHI > 1800	0	0
% Hours HHI > 1800	0%	0%

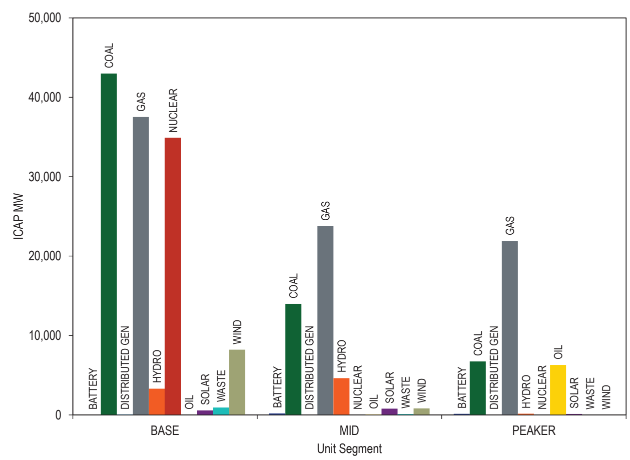
Table 3-3 includes HHI values by supply curve segment, including base, intermediate and peaking plants for 2017 and 2018. The PJM energy market was unconcentrated overall with low concentration in the baseload, moderate concentration in the intermediate segment, and high concentration in the peaking segment.

Table 3-3 Hourly energy market HHI (By supply segment): 2017 and 2018

	2017			2018		
	Minimum	Average	Maximum	Minimum	Average	Maximum
Base	836	983	1273	735	895	1269
Intermediate	718	1542	5124	653	1475	6059
Peak	671	5826	10000	668	5009	10000

Figure 3-1 shows the total installed capacity (ICAP) MW of units in the baseload, intermediate and peaking segments by fuel source in 2018.

Figure 3-1 Fuel source distribution in unit segments: 2018[14]



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

11 See Patrick, Robert H. and Frank A. Wolak (1997), “Estimating the Customer-Level Demand for Electricity Under Real-Time Market Prices, <https://web.stanford.edu/group/fwolak/cgi-bin/sites/default/files/files/Estimating%20the%20Customer-Level%20Demand%20for%20Electricity%20Under%20Real-Time%20Market%20Prices_Aug%201997_Patrick,%20Wolak.pdf>, last accessed August 3, 2018 and Fan, Shu and Rob Hyndman (2010), “The price elasticity of electricity demand in South Australia,” <https://robjhyndman.com/papers/Elasticity2010.pdf>.

12 The HHI used in the equation is based on market shares. For the FERC HHI thresholds and standard HHI reporting, market shares are multiplied by 100 prior to squaring the market shares.

13 This analysis includes all hours in 2017 and 2018, regardless of congestion.

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

Figure 3-2 shows the ICAP of coal fired and gas fired units in PJM that are classified as baseload, intermediate and peaking segments from 2014 through 2018. Figure 3-2 shows that the total ICAP of coal fired units in PJM that are classified as baseload has been steadily decreasing and the total ICAP of gas fired units in PJM that are classified as baseload is steadily increasing using operating history for the period from 2014 through 2018, although coal fired baseload MW still exceed gas fired baseload MW.

Figure 3-2 Unit segment classification by fuel: 2014 through 2018

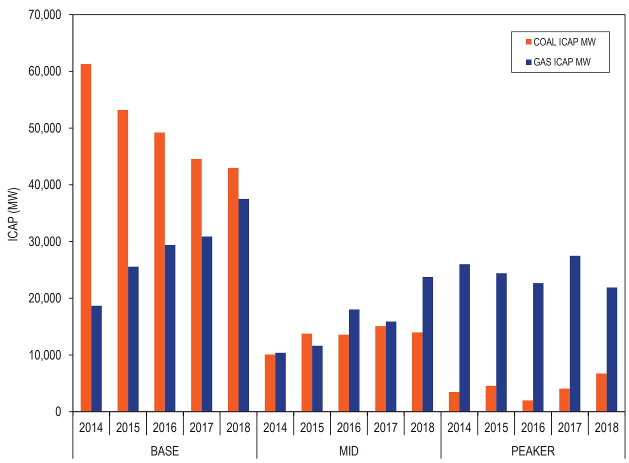
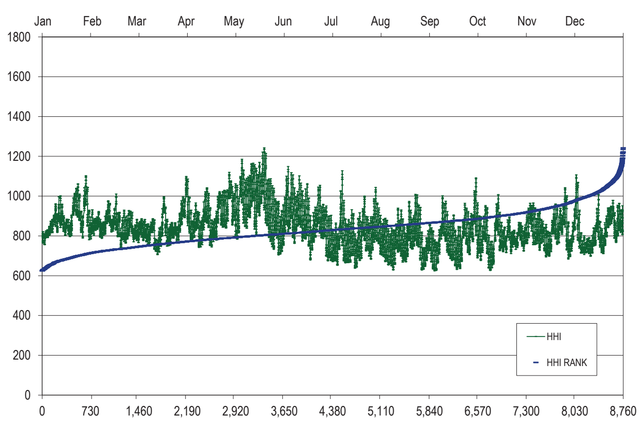


Figure 3-3 presents the hourly HHI values in chronological order and an HHI duration curve for 2018.

Figure 3-3 Hourly energy market HHI: 2018



Merger Reviews

FERC reviews contemplated dispositions, consolidations, acquisitions, and changes in control of jurisdictional generating units and transmission facilities under section 203 of the Federal Power Act to determine whether such transactions are "consistent with the public interest."[15]

FERC applies tests set forth in the 1996 Merger Policy Statement.[16] FERC currently is reviewing those guidelines.[17]

The 1996 Merger Policy Statement provides for review of jurisdictional transactions based on "(1) the effect on competition; (2) the effect on rates; and (3) the effect on regulation." FERC adopted the 1992 Department of Justice Guidelines and the Federal Trade Commission Horizontal Merger Guideline (1992 Guidelines) to evaluate the effect on competition. Following the 1992 Guidelines, the FERC applies a five step framework, which includes: (1) defining the market; (2) analyze market concentration; (3) analyze mitigative effects of new entry; (4) assess efficiency gains; and (5) assess viability of parties without merger. The FERC also applies a Competitive Analysis Screen.

The MMU reviews proposed mergers based on a three pivotal supplier test applied to the actual operation of the PJM market. The MMU routinely files comments including such analyses.[18] The MMU has proposed that FERC adopt this approach when evaluating mergers in PJM.[19] FERC has considered the MMU's analysis in reviewing mergers.[20]

The MMU has also facilitated settlements for mitigation of market power, in cases where market power concerns have been identified.[21] Such mitigation generally is designed to mitigate behavior over the long term, in

15 18 U.S.C. § 824b.

16 See Order No. 592, FERC Stats. & Regs. ¶ 31,044 (1996) (1996 Merger Policy Statement), *reconsideration denied*, Order No. 592-A, 79 FERC ¶ 61,321 (1997). See also FPA Section 203 Supplemental Policy Statement, FERC Stats. & Regs. ¶ 31,253 (2007), *order on clarification and reconsideration*, 122 FERC ¶ 61,157 (2008).

17 See 156 FERC ¶ 61,214 (2016); FERC Docket No. RM16-21-000.

18 See, e.g., Comments of the Independent Market Monitor for PJM, FERC Docket No. EC14-141-000 (Nov. 10, 2014); Comments of the Independent Market Monitor for PJM, FERC Docket No. EC14-96-000 (July 21, 2014) Comments of the Independent Market Monitor for PJM, FERC Docket No. EC11-83-000 (July 21, 2011); Comments of the Independent Market Monitor for PJM, FERC Docket No. EC14-14 (Dec. 9, 2013) Comments of the Independent Market Monitor for PJM, FERC Docket No. EC14-112-000 (Sept. 15, 2014)

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

20 See *Dynegy Inc., et al.*, 150 FERC ¶ 61, 231 (2015); *Exelon Corporation, Constellation Energy Group, Inc.*, 138 FERC ¶ 61,167 (2012); *NRG Energy Holdings, Inc., Edison Mission Energy*, 146 FERC ¶ 61,196 (2014); *see also Analysis of Horizontal Market Power under the Federal Power Act*, 138 FERC ¶ 61,109 (2012).

21 See 138 FERC ¶ 61,167 at P 19.

addition to or instead of imposing short term asset divestiture requirements.

Legislation limiting the scope of section 203 reviews has passed Congress (H.R. 1109). The legislation limits the transactions reviewed to those facilities valued more than $10,000,000. In order to avoid breaking up transactions to evade review, the legislation also requires FERC to establish a notice requirement rule for transactions involving facilities valued at more than $1,000,000. The legislation requires that such rule "minimize the paperwork burden resulting from the collection of information." In February 2019, the Commission issued Order No. 855 amending Section 203 of the Federal Power Act to implement the $10,000,000 minimum value for transactions requiring the Commission's review.[22]

Aggregate Market Pivotal Supplier Results

Notwithstanding the HHI level, a supplier may have the ability to raise energy market prices. If reliably meeting the PJM system load requires energy from a single supplier, that supplier is pivotal and has monopoly power in the aggregate energy market. If a small number of suppliers are jointly required to meet load, those suppliers are jointly pivotal and have oligopoly power. The number of pivotal suppliers in the energy market is a more precise measure of structural market power than the HHI. The HHI is not a definitive measure of structural market power.

In the PJM Day-Ahead Energy Market, two suppliers were jointly pivotal on 11.5 percent of days, and three suppliers were jointly pivotal on 58.0 percent of days in 2018. The frequency of pivotal suppliers increased during the summer months of 2017 and 2018, on high demand days in September 2017 and 2018, and from January 1 to 10, 2018.

The current market power mitigation rules for the PJM energy market rely on the assumption that the aggregate market includes sufficient competing sellers to ensure competitive market outcomes. With sufficient competition, any attempt to economically or physically withhold generation would not result in higher market prices, because another supplier would replace the generation at a similar price. This assumption requires that the total demand for energy can be met without the supply from any individual supplier or without the supply from a small group of suppliers. This assumption is not correct, as demonstrated by these results. There are pivotal suppliers in the aggregate energy market.

The existing market power mitigation measures do not address aggregate market power.[23] The MMU is developing an aggregate market power test for the day-ahead and real-time energy markets based on pivotal suppliers and will propose appropriate market power mitigation rules to address aggregate market power.

Day-Ahead Energy Market Aggregate Pivotal Suppliers

To assess the number of pivotal suppliers in the Day-Ahead Energy Market, the MMU determined, for each supplier, the MW available for economic commitment that were already running or were available to start between the close of the Day-Ahead Energy Market and the peak load hour of the operating day. The available supply is defined as MW offered at a price less than 150 percent of the applicable LMP because supply available at higher prices is not competing to meet the demand for energy.[24] Generating units, import transactions, economic demand response, and INCs, are included for each supplier. Demand is the total MW required by PJM to meet physical load, cleared load bids, export transactions, and DECs. A supplier is pivotal if PJM would require some portion of the supplier's available economic capacity in the peak hour of the operating day in order to meet demand. Suppliers are jointly pivotal if PJM would require some portion of the joint suppliers' available economic capacity in the peak hour of the operating day in order to meet demand.

Figure 3-4 shows the number of days in 2017 and in 2018 with one pivotal supplier, two jointly pivotal suppliers, and three jointly pivotal suppliers for the Day-Ahead Energy Market. No supplier was singly pivotal for any day in 2017 or in 2018. Two suppliers were jointly pivotal on 42 days in 2018. Three suppliers were jointly pivotal on 212 days in 2018, despite average HHIs at persistently unconcentrated levels. In both 2017

22 See 166 FERC ¶ 61,120 (2019), Docket No. RM19-4.

23 One supplier, Exelon, is partially mitigated for aggregate market power through its merger agreement. The agreement is not part of the PJM market rules. See Monitoring Analytics, LLC, Letter attaching Settlement Terms and Conditions, FERC Docket No. EC11-83-000 and Maryland PSC Case No. 9271 (October 11, 2011).

24 Each LMP is scaled by 150 percent to determine the relevant supply, resulting in a different price threshold for each LMP value. The analysis does not solve a redispatch of the PJM market.

and 2018, the highest levels of aggregate market power occur in the third quarter, PJM's peak load season.

Figure 3-4 Days with pivotal suppliers and numbers of pivotal suppliers in the Day-Ahead Energy Market by quarter

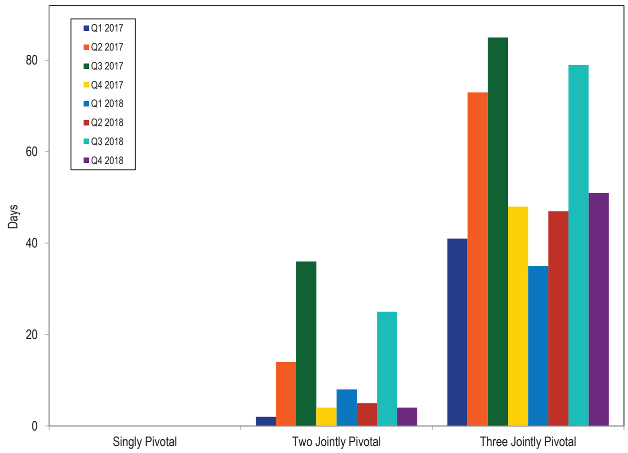


Table 3-4 provides the frequency with which each of the top 10 pivotal suppliers was singly or jointly pivotal for the Day-Ahead Energy Market in 2018. The two largest suppliers were one of two pivotal suppliers on 39 days, 10.7 percent of days in 2018. All of the top 10 suppliers were one of three pivotal suppliers on at least 21.1 percent of days, and the largest two suppliers were one of three pivotal suppliers on at least 55.9 percent of days.

Table 3-4 Day-ahead market pivotal supplier frequency: 2018

Pivotal Supplier Rank	Days Singly Pivotal	Percent of Days	Days Jointly Pivotal with One Other Supplier	Percent of Days	Days Jointly Pivotal with Two Other Suppliers	Percent of Days
1	0	0.0%	39	10.7%	211	57.8%
2	0	0.0%	41	11.2%	204	55.9%
3	0	0.0%	23	6.3%	172	47.1%
4	0	0.0%	16	4.4%	174	47.7%
5	0	0.0%	17	4.7%	165	45.2%
6	0	0.0%	28	7.7%	134	36.7%
7	0	0.0%	3	0.8%	88	24.1%
8	0	0.0%	3	0.8%	84	23.0%
9	0	0.0%	3	0.8%	80	21.9%
10	0	0.0%	5	1.4%	77	21.1%

Ownership of Marginal Resources

Table 3-5 shows the contribution to real-time, load-weighted LMP by individual marginal resource owners.[25] The contribution of each marginal resource to price at each load bus is calculated for each five-minute interval in 2018, and summed by the parent company that offers the marginal resource into the Real-Time Energy Market. In 2018, the offers of one company resulted in 13.6 percent of the real-time, load-weighted PJM system LMP and the offers of the top four companies resulted in 38.5 percent of the real-time, load-weighted, average PJM system LMP. During 2017, the offers of one company resulted in 13.4 percent of the real-time, load-weighted PJM system LMP and offers of the top four companies resulted in 49.1 percent of the real-time, load-weighted, average PJM system LMP. In 2018, the offers of one company resulted in 13.4 percent of the peak hour real-time, load weighted PJM system LMP. In 2017, the offers of one company resulted in 12.3 percent of the peak hour, real-time, load weighted PJM system LMP. The decline in the concentration of marginal resource ownership largely paralleled the decline in the share of marginal coal resources in the real time energy market. In the PJM energy market, the ownership of coal resources is highly concentrated unlike the ownership of new entrant natural gas resources.

25 See the *MMU Technical Reference for PJM Markets*, at "Calculation and Use of Generator Sensitivity/Unit Participation Factors."

Table 3-5 Marginal unit contribution to real-time, load-weighted LMP (By parent company): 2017 and 2018

2017						2018					
All Hours			Peak Hours			All Hours			Peak Hours		
Company	Percent of Price	Cumulative Percent	Company	Percent of Price	Cumulative Percent	Company	Percent of Price	Cumulative Percent	Company	Percent of Price	Cumulative Percent
1	13.4%	13.4%	1	12.3%	12.3%	1	13.6%	13.6%	1	13.4%	13.4%
2	12.6%	26.0%	2	11.7%	24.1%	2	9.8%	23.5%	2	9.8%	23.2%
3	12.5%	38.5%	3	10.6%	34.7%	3	8.1%	31.6%	3	7.6%	30.8%
4	10.6%	49.1%	4	10.3%	45.0%	4	6.9%	38.5%	4	6.8%	37.6%
5	7.6%	56.7%	5	7.7%	52.6%	5	6.4%	44.9%	5	6.1%	43.7%
6	4.7%	61.4%	6	5.8%	58.4%	6	5.0%	49.9%	6	5.3%	49.1%
7	3.7%	65.1%	7	5.0%	63.5%	7	4.4%	54.3%	7	5.1%	54.2%
8	3.5%	68.7%	8	3.7%	67.2%	8	4.3%	58.6%	8	5.1%	59.3%
9	3.2%	71.9%	9	3.5%	70.7%	9	3.8%	62.4%	9	3.2%	62.5%
Other (80 companies)	28.1%	100.0%	Other (73 companies)	29.3%	100.0%	Other (84 companies)	37.6%	100.0%	Other (81 companies)	37.5%	100.0%

Table 3-6 shows the contribution to day-ahead, load-weighted LMP by individual marginal resource owners.[26] The contribution of each marginal resource to price at each load bus is calculated hourly, and summed by the parent company that offers the marginal resource into the Day-Ahead Energy Market. The results show that in 2018, the offers of one company contributed 11.4 percent of the day-ahead, load-weighted, PJM system LMP and that the offers of the top four companies contributed 29.6 percent of the day-ahead, load-weighted, average, PJM system LMP. In 2017, the offers of one company contributed 10.2 percent of the day-ahead, load-weighted PJM system LMP and offers of the top four companies contributed 31.0 percent of the day-ahead, load-weighted, average PJM system LMP.

Table 3-6 Marginal resource contribution to day-ahead, load-weighted LMP (By parent company): 2017 and 2018

2017						2018					
All Hours			Peak Hours			All Hours			Peak Hours		
Company	Percent of Price	Cumulative Percent	Company	Percent of Price	Cumulative Percent	Company	Percent of Price	Cumulative Percent	Company	Percent of Price	Cumulative Percent
1	10.2%	10.2%	1	12.6%	12.6%	1	11.4%	11.4%	1	13.3%	13.3%
2	8.2%	18.4%	2	6.7%	6.7%	2	6.9%	18.3%	2	7.1%	20.3%
3	6.5%	24.9%	3	5.2%	5.2%	3	6.1%	24.4%	3	5.2%	25.5%
4	6.1%	31.0%	4	5.0%	5.0%	4	5.2%	29.6%	4	4.9%	30.4%
5	5.6%	36.5%	5	4.7%	4.7%	5	4.9%	34.5%	5	4.4%	34.8%
6	5.5%	42.1%	6	4.5%	4.5%	6	4.5%	39.0%	6	4.3%	39.1%
7	5.0%	47.0%	7	4.4%	4.4%	7	4.1%	43.1%	7	4.0%	43.1%
8	3.6%	50.7%	8	4.1%	4.1%	8	3.9%	47.1%	8	4.0%	47.2%
9	3.6%	54.3%	9	4.1%	4.1%	9	3.7%	50.8%	9	3.9%	51.0%
Other (167 companies)	45.7%	100.0%	Other (162 companies)	48.6%	48.6%	Other (166 companies)	49.2%	100.0%	Other (155 companies)	49.0%	100.0%

Type of Marginal Resources

LMPs result from the operation of a market based on security-constrained, least-cost dispatch in which marginal resources determine system LMPs, based on their offers. Marginal resource designation is not limited to physical resources in the Day-Ahead Energy Market. INC offers, DEC bids and up to congestion transactions are dispatchable injections and withdrawals in the Day-Ahead Energy Market that can set price via their offers and bids.

Table 3-7 shows the type of fuel used and technology by marginal resources in the Real-Time Energy Market. There can be more than one marginal resource in any given interval as a result of transmission constraints. In 2018, coal units were 27.3 percent and natural gas units were 63.3 percent of marginal resources. In 2018, natural gas combined cycle units were 53.4 percent of marginal resources. In 2017, coal units were 32.3 percent and natural gas units were 53.3 percent of the total marginal resources. In 2017, natural gas combined cycle units were 44.6 percent of the total marginal resources. In 2018, 70.8 percent of the wind marginal units had negative offer prices, 27.1 percent had zero

26 Id.

offer prices and 2.1 percent had positive offer prices. In 2017, 73.3 percent of the wind marginal units had negative offer prices, 20.4 percent had zero offer prices and 6.3 percent had positive offer prices.

The proportion of marginal nuclear units decreased from 1.23 percent in 2017 to 1.04 percent in 2018. Most nuclear units are offered as fixed generation in the PJM market. A small number of nuclear units were offered with a dispatchable range since 2016. The dispatchable nuclear units do not always respond to dispatch instructions.

Table 3-7 Type of fuel used and technology (By real-time marginal units): 2014 through 2018[27]

Fuel	Technology	2014	2015	2016	2017	2018
Gas	CC	25.40%	29.58%	31.22%	44.63%	53.45%
Coal	Steam	52.90%	51.73%	46.39%	32.28%	27.26%
Gas	CT	8.35%	4.16%	6.57%	4.70%	7.80%
Oil	CT	6.55%	5.03%	5.98%	5.18%	4.58%
Wind	Wind	3.29%	3.27%	2.98%	7.28%	2.56%
Gas	Steam	1.81%	3.77%	4.66%	3.53%	1.73%
Uranium	Steam	0.04%	0.03%	1.06%	1.23%	1.04%
Oil	RICE	0.42%	1.26%	0.75%	0.26%	0.42%
Gas	RICE	0.01%	0.05%	0.12%	0.39%	0.36%
Oil	Steam	0.25%	0.13%	0.04%	0.05%	0.29%
Other	Steam	0.43%	0.37%	0.12%	0.19%	0.15%
Oil	CC	0.21%	0.48%	0.02%	0.01%	0.13%
Other	Solar	0.00%	0.01%	0.02%	0.18%	0.12%
Landfill Gas	RICE	0.13%	0.01%	0.04%	0.01%	0.04%
Landfill Gas	Steam	0.07%	0.01%	0.02%	0.05%	0.03%
Landfill Gas	CT	0.04%	0.00%	0.00%	0.01%	0.02%
Municipal Waste	Steam	0.05%	0.06%	0.01%	0.01%	0.01%
Gas	Fuel Cell	0.00%	0.03%	0.00%	0.00%	0.00%
Emergency DR		0.04%	0.00%	0.00%	0.00%	0.00%

Figure 3-5 shows the type of fuel used by marginal resources in the Real-Time Energy Market since 2004. The role of coal as a marginal resource has declined while the role of gas as a marginal resource has increased.

Figure 3-5 Type of fuel used (By real-time marginal units): 2004 through 2018

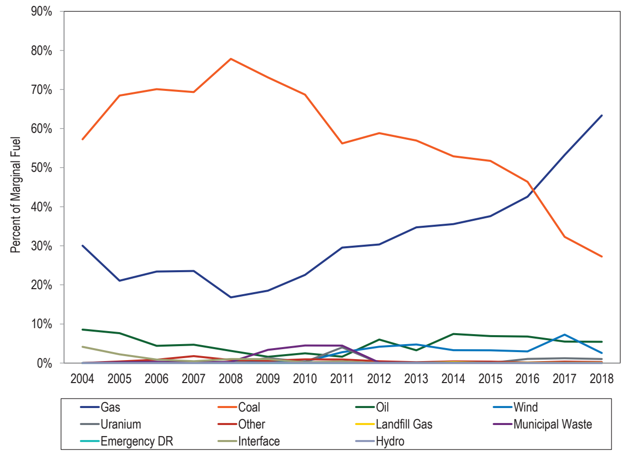


Table 3-8 shows the type and fuel type where relevant, of marginal resources in the Day-Ahead Energy Market. In 2018, up to congestion transactions were 62.3 percent of marginal resources. Up to congestion transactions were 79.9 percent of marginal resources in 2017.

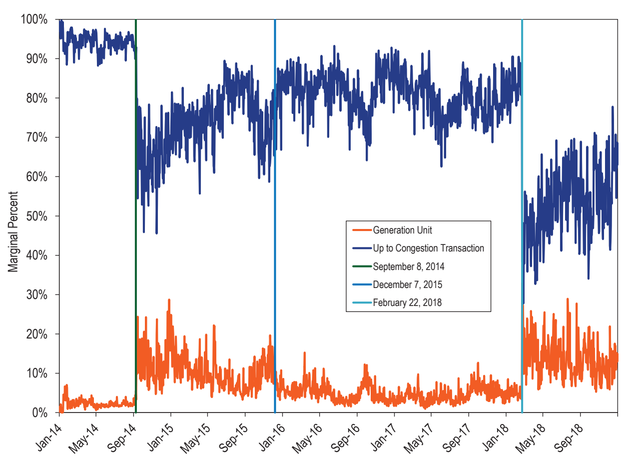
27 The unit type RICE refers to Reciprocating Internal Combustion Engines.

Table 3-8 Day-ahead marginal resources by type/fuel: 2011 through 2018

Type/Fuel	2011	2012	2013	2014	2015	2016	2017	2018
Up to Congestion Transaction	73.40%	88.40%	96.44%	91.05%	76.14%	82.38%	79.88%	62.30%
DEC	12.38%	4.30%	1.27%	3.28%	8.87%	8.64%	10.21%	16.90%
INC	7.54%	3.81%	1.05%	2.28%	5.08%	4.18%	5.53%	9.78%
Gas	1.54%	1.04%	0.36%	1.16%	3.39%	1.99%	1.95%	5.86%
Coal	4.66%	2.31%	0.78%	2.03%	5.54%	2.16%	1.90%	4.63%
Dispatchable Transaction	0.17%	0.07%	0.05%	0.08%	0.26%	0.05%	0.04%	0.13%
Wind	0.07%	0.03%	0.04%	0.05%	0.12%	0.06%	0.15%	0.13%
Uranium	0.00%	0.00%	0.00%	0.00%	0.11%	0.11%	0.08%	0.12%
Oil	0.00%	0.00%	0.00%	0.05%	0.44%	0.41%	0.25%	0.10%
Other	0.00%	0.00%	0.00%	0.00%	0.02%	0.01%	0.00%	0.03%
Price Sensitive Demand	0.23%	0.04%	0.01%	0.01%	0.02%	0.00%	0.00%	0.02%
Hydro	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.01%	0.00%
Municipal Waste	0.01%	0.01%	0.00%	0.01%	0.00%	0.00%	0.00%	0.00%
Total	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%

Figure 3-6 shows, for the Day-Ahead Energy Market from 2014 through 2018, the daily proportion of marginal resources that were up to congestion transaction and/or generation units. The percent of marginal up to congestion transactions (UTC) decreased significantly and that of generation units increased beginning on September 8, 2014, as a result of FERC's UTC uplift refund notice which became effective on that date.[28] That trend reversed as a result of the expiration of the 15 month uplift refund period for UTC transactions. But in 2018, the percent of marginal up to congestion transactions again decreased significantly as the result of a FERC order issued on February 20, 2018, and implemented on February 22, 2018.[29] The order limited UTC trading to hubs, residual metered load, and interfaces. The share of marginal UTCs decreased from 78.9 percent in the period February 22, 2017, through December 31, 2017, to 52.4 percent in the period February 22, 2018, through December 31, 2018. The share of marginal generation resources increased from 4.4 percent in the period February 22, 2017, through December 31, 2017, to 13.6 percent in the period February 22, 2018, through December 31, 2018.

Figure 3-6 Day-ahead marginal up to congestion transaction and generation units: 2014 through 2018



28 See 18 CFR § 385.213 (2014).
29 162 FERC ¶ 61,139 (2018).

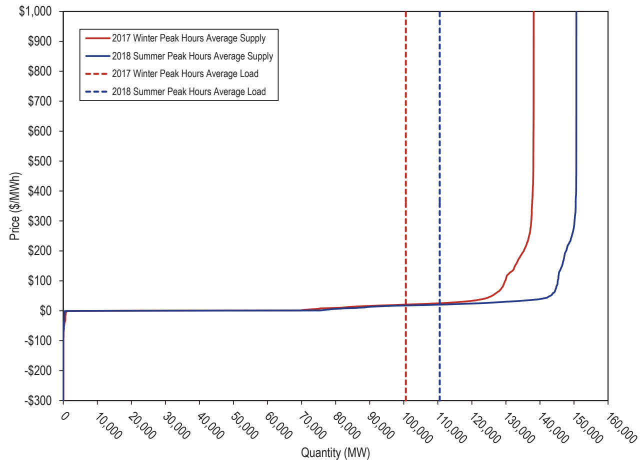
Supply

Supply includes physical generation, imports and virtual transactions.

In 2018, 12,826.2 MW of new resources were added and 5,522.7 MW were retired.

Figure 3-7 shows the average hourly real-time supply and load for the on peak hours of winter of 2017-2018 and summer of 2018. This figure reflects actual available MW from units that are online or available to generate power in one hour including start-up and notification time, and restricted by the ramp limit.

Figure 3-7 Average hourly real-time supply curves: 2017 winter and 2018 summer[30]



Average hourly real-time supply curves are weather sensitive. Figure 3-8 shows the typical dispatch range curve.

Figure 3-8 Typical dispatch range of average hourly real-time supply curves: 2017 winter and 2018 summer

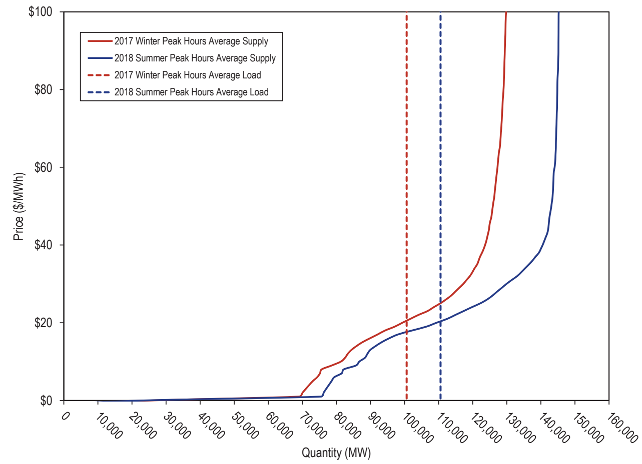
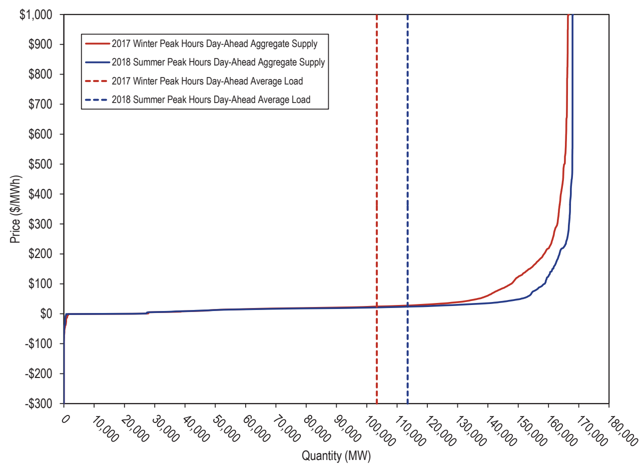


Figure 3-9 is PJM day-ahead generation aggregate supply curve, which includes all day-ahead hourly offers for peak hours of the winter of 2017-2018 and summer of 2018.

Figure 3-9 PJM day-ahead generation aggregate supply curve: 2017 winter and 2018 summer



Energy Production by Fuel Source

Table 3-9 shows PJM generation by fuel source in GWh for 2017 and 2018. In 2018, generation from coal units decreased 6.6 percent, generation from natural gas units increased 18.4 percent, and generation from oil increased 55.6 percent compared to 2017.[31] The increase in gas fired generation exceeded the increase in

30 Winter supply curve period is from Dec 1, 2017, to February 28, 2018. Summer supply curve period is from June 1, 2018 to August 31, 2018.

31 Generation data are the sum of MWh for each fuel by source at every generation bus in PJM with positive output and reflect gross generation without offset for station use of any kind.

total generation, offsetting decreases in coal and nuclear generation. Oil-fired generation also increased, particularly during the first week of January 2018 when gas prices were high.

Table 3-9 Generation (By fuel source (GWh)): 2017 and 2018[32 33 34]

		2017		2018		Change in
		GWh	Percent	GWh	Percent	Output
Coal		256,613.8	31.8%	239,612.1	28.6%	(6.6%)
	Bituminous	220,789.4	27.3%	201,123.6	24.0%	(8.9%)
	Sub Bituminous	28,016.0	3.5%	30,136.0	3.6%	7.6%
	Other Coal	7,808.4	1.0%	8,352.5	1.0%	7.0%
Nuclear		287,575.8	35.6%	286,155.4	34.2%	(0.5%)
Gas		219,205.1	27.1%	259,051.4	30.9%	18.2%
	Natural Gas	216,758.6	26.8%	256,701.9	30.6%	18.4%
	Landfill Gas	2,433.1	0.3%	2,309.7	0.3%	(5.1%)
	Other Gas	13.4	0.0%	39.8	0.0%	197.2%
Hydroelectric		14,868.4	1.8%	19,415.5	2.3%	30.6%
	Pumped Storage	5,132.6	0.6%	5,582.0	0.7%	8.8%
	Run of River	8,119.8	1.0%	12,051.5	1.4%	48.4%
	Other Hydro	1,616.0	0.2%	1,782.0	0.2%	10.3%
Wind		20,714.1	2.6%	21,628.0	2.6%	4.4%
Waste		3,984.1	0.5%	4,507.6	0.5%	13.1%
	Solid Waste	3,740.7	0.5%	4,236.1	0.5%	13.2%
	Miscellaneous	243.4	0.0%	271.5	0.0%	11.5%
Oil		2,301.7	0.3%	3,580.9	0.4%	55.6%
	Heavy Oil	174.4	0.0%	435.5	0.1%	149.7%
	Light Oil	340.3	0.0%	975.2	0.1%	186.5%
	Diesel	81.7	0.0%	363.7	0.0%	345.4%
	Gasoline	0.0	0.0%	0.0	0.0%	NA
	Kerosene	15.2	0.0%	59.7	0.0%	292.0%
	Jet Oil	3.1	0.0%	8.0	0.0%	157.4%
	Other Oil	1,687.0	0.2%	1,738.8	0.2%	3.1%
Solar, Net Energy Metering		1,468.7	0.2%	2,110.6	0.3%	43.7%
Energy Storage		25.1	0.0%	14.4	0.0%	(42.8%)
	Battery	25.1	0.0%	14.4	0.0%	(42.8%)
	Compressed Air	0.0	0.0%	0.0	0.0%	NA
Biofuel		1,473.0	0.2%	1,572.5	0.2%	6.8%
Geothermal		0.0	0.0%	0.0	0.0%	NA
Other Fuel Type		0.0	0.0%	0.0	0.0%	NA
Total		808,229.7	100.0%	837,648.3	100.0%	3.6%

32 All generation is total gross generation output and does not net out the MWh withdrawn at a generation bus to provide auxiliary/parasitic power or station power, power to synchronous condenser motors, or power to run pumped storage pumps.

33 Net Energy Metering is combined with Solar due to data confidentiality reasons.

34 Other Gas includes: Propane, Butane, Hydrogen, Gasified Coal, and Refinery Gas.

Table 3-10 Monthly generation (By fuel source (GWh)): 2018

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Coal	27,514.6	18,362.3	19,734.7	16,225.5	17,690.3	20,391.4	23,679.9	24,251.4	17,905.8	16,280.3	17,458.5	20,117.4	239,612.1
Bituminous	23,012.8	15,782.6	16,374.3	13,731.6	15,089.2	16,893.9	19,973.4	20,393.5	14,734.3	13,282.5	14,572.2	17,283.3	201,123.6
Sub Bituminous	3,544.9	1,876.0	2,571.7	1,983.3	2,180.8	2,850.0	2,930.4	3,098.3	2,547.4	2,403.7	2,116.0	2,033.4	30,136.0
Other Coal	956.9	703.7	788.7	510.6	420.2	647.5	776.1	759.6	624.1	594.1	770.4	800.6	8,352.5
Nuclear	26,301.0	22,971.9	22,554.2	20,630.7	24,040.7	24,681.3	25,265.5	24,912.7	23,245.2	22,514.7	23,386.9	25,650.6	286,155.4
Gas	18,503.1	17,732.1	20,075.1	17,485.3	19,318.7	22,028.6	27,463.3	28,412.6	25,564.1	21,424.4	19,860.3	21,183.7	259,051.4
Natural Gas	18,303.6	17,543.4	19,869.9	17,294.7	19,126.2	21,845.5	27,270.6	28,222.9	25,368.6	21,220.9	19,654.3	20,981.3	256,701.9
Landfill Gas	199.5	188.7	205.2	190.6	192.6	182.8	190.1	189.8	184.8	190.0	193.2	202.4	2,309.7
Other Gas	0.0	0.0	0.0	0.0	0.0	0.3	2.6	0.0	10.7	13.5	12.7	0.0	39.8
Hydroelectric	1,194.4	1,301.4	1,354.2	1,526.9	1,797.3	1,623.8	1,605.3	2,045.6	1,742.1	1,769.4	1,766.1	1,689.1	19,415.5
Pumped Storage	384.8	324.9	388.4	402.2	480.5	602.0	665.4	724.1	525.3	387.2	350.9	346.2	5,582.0
Run of River	685.7	879.0	865.0	987.7	1,151.5	795.6	700.1	1,079.7	1,052.0	1,268.0	1,325.6	1,261.7	12,051.5
Other Hydro	123.8	97.4	100.8	137.1	165.2	226.3	239.8	241.8	164.8	114.2	89.7	81.3	1,782.0
Wind	2,857.3	2,149.0	2,389.0	2,045.6	1,521.3	1,119.4	883.8	987.5	1,167.2	2,083.2	2,090.8	2,334.1	21,628.0
Waste	378.8	351.9	367.1	352.5	364.2	394.2	400.0	409.1	339.1	390.6	365.5	394.7	4,507.6
Solid Waste	354.3	329.2	341.9	329.3	345.6	371.9	378.3	387.2	317.9	366.4	343.2	370.9	4,236.1
Miscellaneous	24.5	22.7	25.2	23.1	18.6	22.3	21.7	21.8	21.2	24.3	22.3	23.8	271.5
Oil	1,538.4	155.3	123.3	196.6	233.7	282.3	185.5	196.8	154.7	150.4	174.8	189.1	3,580.9
Heavy Oil	257.0	0.0	0.0	0.0	32.6	138.5	6.0	1.0	0.0	0.0	0.0	0.4	435.5
Light Oil	728.0	11.8	6.8	37.5	33.6	7.8	17.9	32.0	24.4	30.3	20.1	24.9	975.2
Diesel	330.5	0.7	1.7	4.9	7.0	5.8	6.3	1.3	0.8	1.1	1.2	2.6	363.7
Gasoline	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Kerosene	55.6	0.0	0.0	0.9	0.0	0.0	2.2	0.0	0.1	0.5	0.4	0.0	59.7
Jet Oil	8.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	8.0
Other Oil	159.3	142.9	114.9	153.3	160.5	130.2	153.1	162.5	129.3	118.6	153.1	161.1	1,738.8
Solar, Net Energy Metering	113.6	100.6	177.0	220.5	221.9	242.6	241.9	236.7	154.7	169.6	125.1	106.5	2,110.6
Energy Storage	1.4	1.0	1.4	1.4	1.3	1.2	1.1	0.9	1.0	1.3	1.0	1.5	14.4
Battery	1.4	1.0	1.4	1.4	1.3	1.2	1.1	0.9	1.0	1.3	1.0	1.5	14.4
Compressed Air	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Biofuel	170.3	129.9	160.3	110.4	145.3	160.6	162.3	147.7	119.8	98.4	98.9	68.5	1,572.5
Geothermal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Other Fuel Type	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total	78,572.9	63,255.5	66,936.2	58,795.3	65,334.5	70,925.6	79,888.6	81,600.8	70,393.7	64,882.3	65,327.8	71,735.1	837,648.3

Generator Offers

Generator offers are categorized as dispatchable (Table 3-11) or self scheduled (Table 3-12).[35] Units which are available for economic dispatch are dispatchable. Units which are self scheduled to generate fixed output are self scheduled and must run. Units which are self scheduled at their economic minimum and are available for economic dispatch up to their economic maximum are self scheduled and dispatchable. Table 3-11 and Table 3-12 do not include units that did not indicate their offer status or units that were offered as available to run only during emergency events. Units that do not indicate their offer status are unavailable for dispatch by PJM. The MW offered beyond the economic range of a unit are categorized as emergency MW. Emergency MW are included in both tables. Generators may have multiple available offers. In order to select one offer, if there are active emergency conditions a PLS offer is used, if there is no active emergency the cheapest price-based offer is used, if there is no price-based offer a cost-based offer is used, and if there are multiple cost-based offers the cheapest commitment cost-based offer is used.

Table 3-11 shows the proportion of day-ahead MW offered by dispatchable units, by unit type, fuel type and by offer price range, in 2018. For example, 41.6 percent of all CC units using diesel offers were the economic minimum offered MW and 19.3 percent of CC units using diesel offers were dispatchable and in the $0 to $200 per MWh offer price range. The total column is the proportion of all MW offers by unit type that were dispatchable. For example, 86.7 percent of all CC units using diesel MW offers were dispatchable, including the 0.0 percent of emergency MW offered by CC units. The all dispatchable offers row is the proportion of MW that were offered as available for economic dispatch within a given range by all unit types. For example, 22.0 percent of all dispatchable offers were in the $0 to $200 per MWh price range. The total column in the all dispatchable offers row is the proportion of all MW offers

35 Each range in the tables is greater than or equal to the lower value and less than the higher value. The unit type battery is not included in these tables because batteries do not make energy offers. The unit type fuel cell is not included in these tables because of the small number of owners and the small number of units.

that were offered as available for economic dispatch, including emergency MW. Among all the generator offers in 2018, 25.4 percent were offered as available for economic dispatch, excluding emergency MW and economic minimum MW (61.1 percent less 4.5 and 31.3 percent).

Table 3-11 Distribution of day-ahead MW for dispatchable unit offer prices: 2018

			Dispatchable (Range)							
Unit Type	Fuel Type	Economic Minimum	($200) - $0	$0 - $200	$200 - $400	$400 - $600	$600 - $800	$800 - $1,000	Emergency	Total
Battery	Battery	0.0%	0.0%	66.3%	0.0%	0.0%	0.0%	0.0%	0.0%	66.3%
CC	Diesel	41.6%	0.0%	19.3%	15.0%	9.4%	1.4%	0.0%	0.0%	86.7%
	Light Oil	69.8%	0.0%	25.4%	0.0%	0.0%	0.0%	0.0%	0.3%	95.5%
	Natural Gas	44.3%	0.0%	34.9%	0.6%	0.2%	0.0%	0.0%	4.4%	84.3%
CT	Coal	1.6%	0.0%	32.0%	0.0%	0.0%	0.0%	0.0%	0.0%	33.6%
	Diesel	91.7%	0.0%	1.7%	4.7%	0.0%	0.0%	0.0%	2.0%	100.0%
	Heavy Oil	98.0%	0.0%	0.0%	2.0%	0.0%	0.0%	0.0%	0.0%	100.0%
	Kerosene	83.9%	0.0%	0.0%	2.1%	12.4%	0.0%	0.0%	1.4%	99.7%
	LFG	11.7%	0.0%	17.4%	0.2%	0.1%	0.0%	0.1%	0.8%	30.2%
	Light Oil	56.4%	0.0%	15.3%	7.1%	3.6%	0.3%	0.0%	17.2%	99.9%
	Natural Gas	67.4%	0.0%	26.0%	0.9%	0.1%	0.0%	0.0%	4.7%	99.1%
Diesel	Diesel	96.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	4.0%	100.0%
	LFG	20.1%	0.0%	11.1%	1.1%	0.0%	0.0%	0.0%	15.5%	47.9%
	Light Oil	51.7%	0.0%	1.5%	23.8%	0.6%	0.0%	0.0%	22.4%	100.0%
	Natural Gas	51.0%	0.0%	34.4%	0.0%	0.0%	0.0%	0.0%	14.6%	100.0%
Fuel Cell	Fuel Cell	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Nuclear	Nuclear	6.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	6.1%
Pumped Storage	Hydro	0.0%	0.0%	9.5%	0.0%	0.0%	0.0%	0.0%	40.1%	49.6%
Run of River	Hydro	0.0%	0.0%	0.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.1%
Solar	Solar	0.0%	0.0%	5.5%	0.0%	0.0%	0.0%	0.0%	0.0%	5.5%
Steam	Coal	21.5%	0.0%	24.4%	0.6%	0.0%	0.0%	0.0%	1.7%	48.2%
	Diesel	9.9%	0.0%	67.0%	21.9%	0.0%	0.0%	0.0%	0.0%	98.8%
	Heavy Oil	25.1%	0.0%	61.7%	3.7%	0.1%	0.0%	0.0%	8.7%	99.3%
	LFG	0.5%	0.0%	0.2%	0.0%	0.2%	0.0%	0.0%	0.0%	0.8%
	Light Oil	31.3%	0.0%	27.6%	30.4%	0.0%	0.0%	0.0%	0.8%	90.1%
	Misc	28.1%	0.0%	35.3%	0.0%	0.0%	0.0%	0.0%	0.8%	64.2%
	Natural Gas	39.7%	0.0%	49.3%	2.9%	0.0%	0.1%	0.1%	2.9%	94.9%
	Propane	18.1%	0.0%	2.2%	1.1%	45.9%	0.1%	9.3%	0.1%	76.7%
	Waste Coal	21.1%	0.0%	18.2%	0.0%	0.0%	0.0%	0.0%	3.3%	42.5%
Transaction		0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Wind	Wind	2.3%	0.0%	9.7%	0.0%	0.0%	0.0%	0.0%	2.3%	14.3%
All Dispatchable Offers		31.3%	0.0%	22.0%	1.0%	0.2%	0.0%	0.0%	4.5%	61.1%

Table 3-12 shows the proportion of day-ahead MW offers by unit type that were self scheduled to generate fixed output and by unit type, fuel type and price range for self scheduled and dispatchable units, for 2018. For example, 8.1 percent of CC units using natural gas offers were the economic minimum and 5.7 percent of CC offers were self scheduled and dispatchable and in the $0 to $200 offer price range. The total column is the proportion of all MW offers by unit type that were self scheduled to generate fixed output or are self scheduled and dispatchable. For example, 15.6 percent of all CC units using natural gas MW offers were either self scheduled to generate at fixed output or self scheduled to generate at economic minimum and dispatchable up to economic maximum, including the 1.0 percent of emergency MW offered by CC units. The all self scheduled offers row is the proportion of MW that were offered as either self scheduled to generate at fixed output or self scheduled to generate at economic minimum and dispatchable up to economic maximum within a given range by all unit types. For example, units that were self scheduled to generate at fixed output accounted for 15.4 percent of all offers and self scheduled and dispatchable units accounted for 16.2 percent of all offers. The total column in the all self scheduled offers row is the proportion of all MW offers that were either self scheduled to generate at fixed output or self scheduled to generate at economic minimum and dispatchable up to economic maximum, including emergency MW. Among all the generator offers in 2018, 16.2 percent were offered as self scheduled and 21.5 percent were offered as self scheduled and dispatchable.

Table 3-12 Distribution of day-ahead MW for self scheduled and dispatchable unit offer prices: 2018

		Self Scheduled		Self Scheduled and Dispatchable (Range)								
Unit Type		Must Run	Emergency	Economic Minimum	($200) - $0	$0 - $200	$200 - $400	$400 - $600	$600 - $800	$800 - $1,000	Emergency	Total
CC	Coal gas	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
	Light oil	0.1%	0.0%	2.7%	0.0%	1.7%	0.0%	0.0%	0.0%	0.0%	0.0%	4.5%
	Natural gas	0.6%	0.2%	8.1%	0.0%	5.7%	0.1%	0.0%	0.0%	0.0%	1.0%	15.6%
CT	Coal	0.9%	0.5%	37.5%	0.0%	7.3%	0.0%	0.0%	0.0%	0.0%	20.2%	66.4%
	Kerosene	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
	LFG	63.6%	0.0%	2.2%	0.0%	3.9%	0.0%	0.0%	0.0%	0.0%	0.0%	69.8%
	Light oil	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.1%
	Natural gas	0.2%	0.0%	0.5%	0.0%	0.2%	0.0%	0.0%	0.0%	0.0%	0.0%	0.9%
Diesel	LFG	40.5%	0.6%	2.9%	0.0%	0.7%	0.0%	0.0%	0.0%	0.0%	0.1%	44.8%
	Light oil	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
	MSW	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Fuel Cell	Natural gas	100.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	100.0%
Nuclear	Nuclear	64.5%	0.0%	23.4%	0.0%	2.1%	0.0%	0.0%	0.0%	0.0%	0.0%	90.0%
Pumped Storage	Hydro	4.6%	5.9%	0.3%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	10.9%
Run of River	Hydro	84.5%	11.1%	0.7%	0.0%	3.4%	0.0%	0.0%	0.0%	0.0%	0.0%	99.7%
Solar	Solar	16.0%	2.7%	0.0%	0.0%	1.4%	0.0%	0.0%	0.0%	0.0%	0.0%	20.0%
Steam	Coal	3.1%	0.9%	23.9%	0.0%	22.3%	0.0%	0.0%	0.0%	0.0%	1.5%	51.7%
	Diesel	0.0%	0.0%	0.4%	0.0%	0.2%	0.3%	0.0%	0.0%	0.0%	0.3%	1.2%
	Heavy Oil	0.1%	0.1%	0.1%	0.0%	0.4%	0.0%	0.0%	0.0%	0.0%	0.0%	0.7%
	LFG	12.9%	0.1%	43.0%	0.0%	9.2%	0.2%	0.1%	0.0%	0.2%	0.0%	65.6%
	MISC	1.5%	0.4%	19.2%	0.0%	6.2%	0.0%	0.0%	2.0%	0.0%	4.3%	33.5%
	MSW	53.3%	15.5%	12.9%	0.0%	0.6%	0.0%	0.0%	0.0%	0.0%	1.7%	83.9%
	Natural gas	0.3%	0.1%	1.7%	0.0%	2.6%	0.2%	0.0%	0.0%	0.0%	0.1%	5.1%
	Waste coal	16.6%	2.6%	21.5%	0.0%	13.2%	0.1%	0.0%	0.0%	0.0%	0.9%	55.0%
Transaction		0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Wind	Wind	7.4%	7.4%	3.4%	0.0%	0.7%	0.0%	0.0%	0.0%	0.0%	3.4%	22.3%
All Self-Scheduled Offers		15.4%	0.8%	13.1%	0.0%	7.7%	0.0%	0.0%	0.0%	0.0%	0.7%	38.9%

Fuel Diversity

Figure 3-10 shows the fuel diversity index (FDI_e) for PJM energy generation.[36] The FDI_e is defined as $1-\sum_{i=1}^{N} s_i^2$, where s_i is the share of fuel type i. The minimum possible value for the FDI_e is zero, corresponding to all generation from a single fuel type. The maximum possible value for the FDI_e results when each fuel type has an equal share of total generation. For a generation fleet composed of 10 fuel types, the maximum achievable index is 0.9. The fuel type categories used in the calculation of the FDI_e are the 10 primary fuel sources in Table 3-10 with nonzero generation values. As fuel diversity has increased, seasonality in the FDI_e has decreased and the FDI_e has exhibited less volatility. Since 2012, the monthly FDI_e has been less volatile as a result of the decline in the share of coal from 51.3 percent prior to 2012 to 38.6 percent from 2012 through 2018. A significant drop in the FDI_e occurred in the fall of 2004 as a result of the expansion of the PJM market footprint into ComEd, AEP, and Dayton Power & Light control zones and the increased shares of coal and nuclear that resulted.[37] The increasing trend that began in 2008 is a result of decreasing coal generation, increasing gas generation and increasing wind generation. Coal generation as a share of total generation was 54.9 percent for 2008 and 28.6 percent for 2018, a decrease of 26.3 percentage points. Gas generation as a share of total generation was 7.4 percent for 2008 and 30.9 percent for 2018, an increase of 23.5 percentage points. Wind generation as a share of total generation was 0.5 percent for 2008 and 2.6 percent for 2018, an increase of 2.1 percentage points.

The average FDI_e increased 0.9 percent in 2018 compared to 2017. The FDI_e was also used to measure the impact on fuel diversity of potential retirements by resources that have been identified as at risk of retirement by the MMU's net revenue adequacy analysis.[38] There were 27 units with installed capacity totaling 14,954 MW

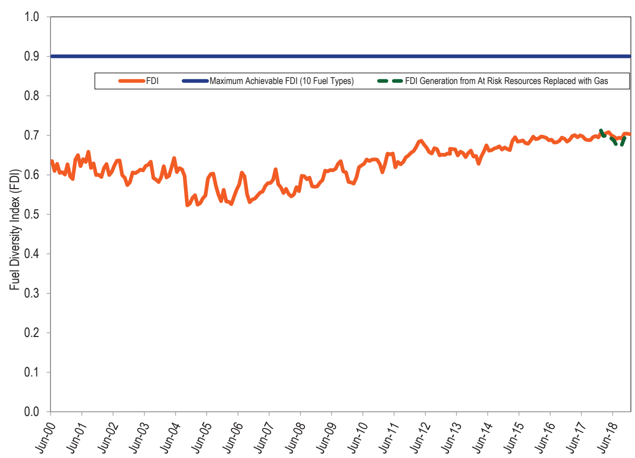
36 Monitoring Analytics developed the FDI to provide an objective metric of fuel diversity. The FDI metric is similar to the HHI used to measure market concentration. The FDI is calculated separately for energy output and for installed capacity.

37 See the *2018 State of the Market Report for PJM*, Volume 2, Appendix A, "PJM Geography" for an explanation of the expansion of the PJM footprint. The integration of the ComEd Control Area occurred in May 2004 and the integration of the AEP and Dayton control zones occurred in October 2004.

38 See the *2018 State of the Market Report for PJM*, Volume 2, Section 7: Net Revenue, Units at Risk.

identified as being at risk of retirement. The at risk units consists of 12,017 MW of coal and 2,937 MW of nuclear capacity. The at risk units generated 67.8 GWh in 2018. The dashed line in Figure 3-10 shows the FDI_e calculated assuming the 67.8 GWh of generation from at risk resources, were replaced by gas generation. The FDI_e under these assumptions increased by 0.9 percent in January and would have decreased in each of the remaining eleven months with an average monthly decrease of 1.3 percent compared to the actual FDI_e.

Figure 3-10 Fuel diversity index for monthly generation: June 2000 through December 2018



Net Generation and Load

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

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

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

Real-Time Supply

The maximum of average on-peak hour offered real-time supply was 138,142 MWh for winter of 2017, and 150,674 MWh for summer of 2018.

PJM average real-time cleared generation in 2018 increased by 3.6 percent from 2017, from 90,945 MWh to 94,236 MWh.[39]

PJM average, real-time cleared supply, including imports in 2018 increased by 3.7 percent from 2017, from 92,721 MWh to 96,109 MWh.

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

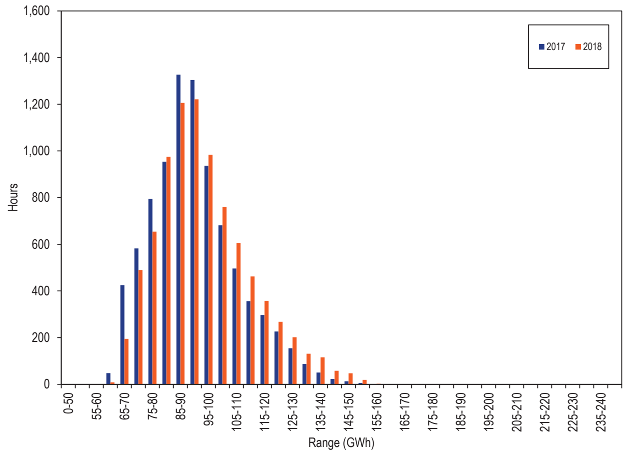
- **Self Scheduled Generation Offer.** Offer to supply a fixed block of MWh, as a price taker, from a unit that may also have a dispatchable component above the minimum.
- **Dispatchable Generation Offer.** Offer to supply a schedule of MWh and corresponding offer prices from a specific unit.
- **Import.**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

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

PJM Real-Time Supply Duration

Figure 3-11 shows the hourly distribution of PJM real-time generation plus imports for 2017 and 2018.

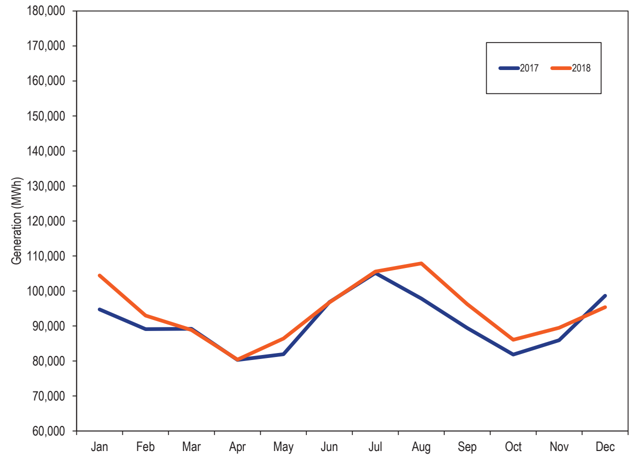
Figure 3-11 Distribution of real-time generation plus imports: 2017 and 2018[40]



PJM Real-Time, Monthly Average Generation

Figure 3-12 compares the real-time, monthly average hourly generation in 2017 and 2018

Figure 3-12 Real-time monthly average hourly generation: 2017 through 2018



PJM Real-Time, Average Supply

Table 3-13 presents summary average real-time hourly supply statistics for each year for 18-year period from 2001 through 2018.

Table 3-13 Average hourly real-time generation and real-time generation plus imports: 2001 through 2018

	PJM Real-Time Supply (MWh)				Year-to-Year Change			
	Generation		Generation Plus Imports		Generation		Generation Plus Imports	
	Generation	Standard Deviation	Supply	Standard Deviation	Generation	Standard Deviation	Supply	Standard Deviation
2001	29,553	4,937	32,552	5,285	NA	NA	NA	NA
2002	34,928	7,535	38,535	7,751	18.2%	52.6%	18.4%	46.7%
2003	36,628	6,165	40,205	6,162	4.9%	(18.2%)	4.3%	(20.5%)
2004	51,068	13,790	55,781	14,652	39.4%	123.7%	38.7%	137.8%
2005	81,127	15,452	86,353	15,981	58.9%	12.0%	54.8%	9.1%
2006	82,780	13,709	86,978	14,402	2.0%	(11.3%)	0.7%	(9.9%)
2007	85,860	14,018	90,351	14,763	3.7%	2.3%	3.9%	2.5%
2008	83,476	13,787	88,899	14,256	(2.8%)	(1.7%)	(1.6%)	(3.4%)
2009	78,026	13,647	83,058	14,140	(6.5%)	(1.0%)	(6.6%)	(0.8%)
2010	82,585	15,556	87,386	16,227	5.8%	14.0%	5.2%	14.8%
2011	85,775	15,932	90,511	16,759	3.9%	2.4%	3.6%	3.3%
2012	88,708	15,701	94,083	16,505	3.4%	(1.4%)	3.9%	(1.5%)
2013	89,769	15,012	94,833	15,878	1.2%	(4.4%)	0.8%	(3.8%)
2014	90,894	15,151	96,295	16,199	1.3%	0.9%	1.5%	2.0%
2015	88,628	16,118	94,330	17,313	(2.5%)	6.4%	(2.0%)	6.9%
2016	91,304	17,731	95,054	17,980	3.0%	10.0%	0.8%	3.9%
2017	90,945	15,194	92,721	15,493	(0.4%)	(14.3%)	(2.5%)	(13.8%)
2018	94,236	16,326	96,109	16,595	3.6%	7.5%	3.7%	7.1%

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

Day-Ahead Supply

PJM average, day-ahead cleared supply in 2018, including INCs and up to congestion transactions, decreased by 12.3 percent from 2017, from 130,601 MWh to 114,556 MWh.

PJM average, day-ahead cleared supply in 2018, including INCs, up to congestion transactions, and imports, decreased by 12.3 percent from 2017, from 131,140 MWh to 114,967 MWh.

The significant decrease in up to congestion transactions (UTC) is a result of the reduction in the number of UTC trading points as directed in the FERC order issued February 20, 2018.[41]

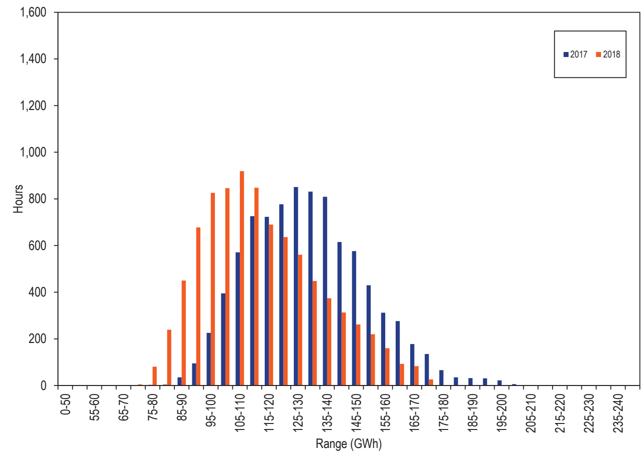
In the PJM Day-Ahead Energy Market, there are five types of financially binding supply offers:

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

PJM Day-Ahead Supply Duration

Figure 3-13 shows the hourly distribution of PJM day-ahead supply, including increment offers, up to congestion transactions, and imports for 2017 and 2018.

Figure 3-13 Distribution of day-ahead supply plus imports: 2017 and 2018[42]



PJM Day-Ahead, Average Supply

Table 3-14 presents summary average day-ahead hourly supply statistics for the 18-year period from 2001 through 2018.

41 162 FERC ¶ 61,139.

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

Table 3-14 Average hourly day-ahead supply and day-ahead supply plus imports: 2001 through 2018

	PJM Day-Ahead Supply (MWh)				Year-to-Year Change			
	Supply		Supply Plus Imports		Supply		Supply Plus Imports	
	Supply	Standard Deviation	Supply	Standard Deviation	Supply	Standard Deviation	Supply	Standard Deviation
2001	26,762	4,595	27,497	4,664	NA	NA	NA	NA
2002	31,434	10,007	31,982	10,015	17.5%	117.8%	16.3%	114.7%
2003	40,642	8,292	41,183	8,287	29.3%	(17.1%)	28.8%	(17.3%)
2004	62,755	17,141	63,654	17,362	54.4%	106.7%	54.6%	109.5%
2005	94,438	17,204	96,449	17,462	50.5%	0.4%	51.5%	0.6%
2006	100,056	16,543	102,164	16,559	5.9%	(3.8%)	5.9%	(5.2%)
2007	108,707	16,549	111,023	16,729	8.6%	0.0%	8.7%	1.0%
2008	105,485	15,994	107,885	16,136	(3.0%)	(3.4%)	(2.8%)	(3.5%)
2009	97,388	16,364	100,022	16,397	(7.7%)	2.3%	(7.3%)	1.6%
2010	107,307	21,655	110,026	21,837	10.2%	32.3%	10.0%	33.2%
2011	117,130	20,977	119,501	21,259	9.2%	(3.1%)	8.6%	(2.6%)
2012	134,479	17,905	136,903	18,080	14.8%	(14.6%)	14.6%	(15.0%)
2013	148,323	18,783	150,595	18,978	10.3%	4.9%	10.0%	5.0%
2014	146,672	33,145	148,906	33,346	(1.1%)	76.5%	(1.1%)	75.7%
2015	114,890	19,165	117,147	19,406	(21.7%)	(42.2%)	(21.3%)	(41.8%)
2016	131,618	22,329	133,246	22,368	14.6%	16.5%	13.7%	15.3%
2017	130,603	20,035	131,142	20,153	(0.8%)	(10.3%)	(1.6%)	(9.9%)
2018	114,556	20,239	114,967	20,224	(12.3%)	1.0%	(12.3%)	0.4%

PJM Day-Ahead, Monthly Average Supply

Figure 3-14 compares the day-ahead, monthly average hourly supply, including increment offers and up to congestion transactions for 2017 and 2018.

Figure 3-14 Day-ahead monthly average hourly supply: 2017 through 2018

Real-Time and Day-Ahead Supply

Table 3-15 presents summary statistics for 2017 and 2018, for day-ahead and real-time supply. All data are cleared MWh. The last two columns of Table 3-15 are the day-ahead supply minus the real-time supply. The first of these columns is the total day-ahead supply less the total real-time supply and the second of these columns is the total physical day-ahead generation less the total physical real-time generation. In 2018, up to congestion transactions were 15.3 percent of the total day-ahead supply compared to 26.6 percent in 2017. The nearly fifty percent reduction in UTCs clearing in the day-ahead market directly resulted in an increase in the amount of physical generation clearing in the day-ahead market. While day-ahead generation and total supply still exceeded real-time generation and total supply, the difference is smaller.

Table 3-15 Day-ahead and real-time supply (MWh): 2017 and 2018

		Day-Ahead					Real-Time		Day-Ahead Less Real-Time	
		Generation	INC Offers	Up to Congestion	Imports	Total Supply	Generation	Total Supply	Total Supply	Total Generation
Average	2017	91,112	4,562	34,927	539	131,140	90,945	92,721	38,419	167
	2018	94,255	2,676	17,624	412	114,967	94,236	96,109	18,858	19
Median	2017	89,647	4,396	33,823	331	129,870	89,089	90,837	39,033	558
	2018	91,969	2,552	16,453	376	111,917	91,810	93,574	18,342	159
Standard Deviation	2017	15,883	1,472	8,226	490	20,153	15,194	15,493	4,660	689
	2018	16,598	1,112	7,210	244	20,224	16,326	16,595	3,629	272
Peak Average	2017	100,259	4,995	37,172	502	142,928	99,423	101,356	41,572	836
	2018	103,279	3,268	18,590	397	125,534	102,719	104,799	20,734	559
Peak Median	2017	96,569	4,816	36,106	273	140,706	95,812	97,936	42,770	756
	2018	100,784	3,198	17,163	360	123,122	99,753	101,662	21,460	1,031
Peak Standard Deviation	2017	13,448	1,430	8,162	483	16,972	13,405	13,619	3,353	43
	2018	14,623	1,119	7,633	267	18,104	14,820	14,938	3,166	(197)
Off-Peak Average	2017	83,195	4,187	32,985	571	120,939	83,607	85,248	35,691	(411)
	2018	86,389	2,160	16,783	424	105,756	86,841	88,533	17,222	(452)
Off-Peak Median	2017	81,151	3,939	31,925	360	118,230	81,461	83,017	35,214	(310)
	2018	84,123	2,099	15,774	386	101,952	84,482	86,006	15,946	(359)
Off-Peak Standard Deviation	2017	13,380	1,404	7,775	493	16,854	12,613	12,919	3,935	767
	2018	14,016	806	6,708	222	17,254	13,786	14,062	3,192	230

Figure 3-15 shows the average hourly cleared volumes of day-ahead supply and real-time supply for 2018. The day-ahead supply consists of cleared MW of day-ahead generation, imports, increment offers and up to congestion transactions. The real-time generation includes generation and imports.

Figure 3-15 Day-ahead and real-time supply (Average hourly volumes): 2018

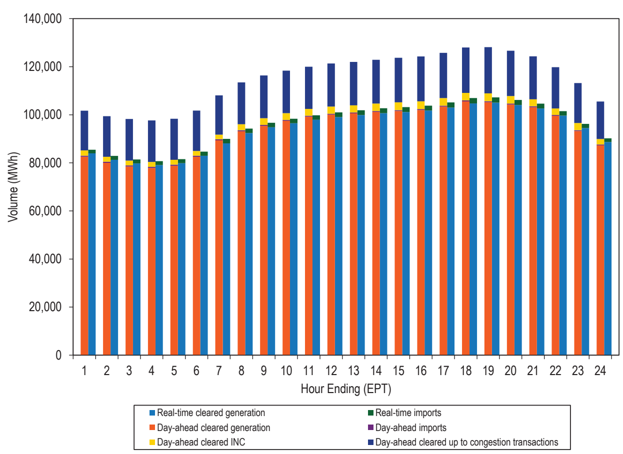


Figure 3-16 shows the difference between the day-ahead and real-time average daily supply for 2017 and 2018.

Figure 3-16 Difference between day-ahead and real-time supply (Average daily volumes): 2017 through 2018

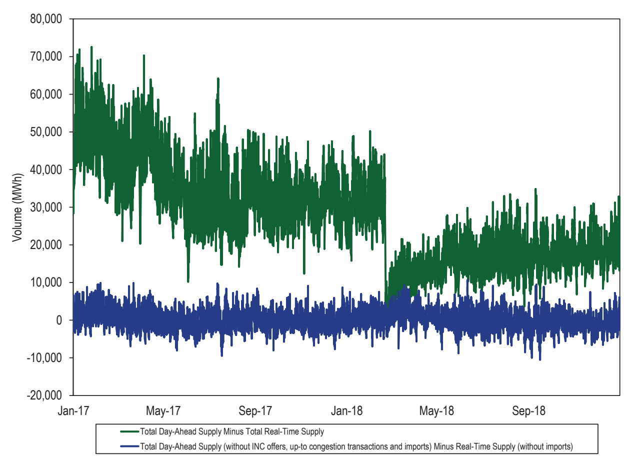
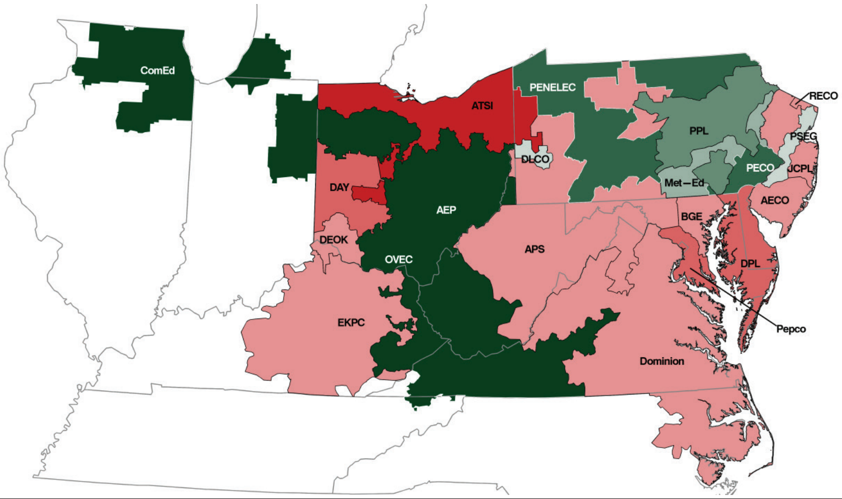


Figure 3-17 shows the difference between the PJM real-time generation and real-time load by zone in 2018. Figure 3-17 is color coded using a scale on which red shades represent zones that have less generation than load and green shades represent zones that have more generation than load, with darker shades meaning greater amounts of net generation or load. For example, the Pepco Control Zone has less generation than load, while the PENELEC Control Zone has more generation than load. Table 3-16 shows the difference between the PJM real-time generation and real-time load by zone in 2017 and 2018.

Figure 3-17 Map of real-time generation, less real-time load, by zone: 2018[43]



Zone	Net Gen Minus Load (GWh)	Zone	Net Gen Minus Load (GWh)	Zone	Net Gen Minus Load (GWh)	Zone	Net Gen Minus Load (GWh)
AECO	(4,581)	DAY	(13,047)	JCPL	(8,051)	PPL	16,317
AEP	31,999	DEOK	(8,005)	Met-Ed	7,011	PSEG	3,318
APS	(2,863)	Dominion	(4,610)	OVEC	1,079	RECO	(1,484)
ATSI	(27,308)	DPL	(12,440)	PECO	26,325		
BGE	(10,474)	DLCO	2,030	PENELEC	25,581		
ComEd	35,585	EKPC	(4,138)	Pepco	(17,828)		

Table 3-16 Real-time generation less real-time load by zone (GWh): 2017 and 2018

	Zonal Generation and Load (GWh)					
	2017			2018		
Zone	Generation	Load	Net	Generation	Load	Net
AECO	6,408.9	9,724.0	(3,315.1)	5,555.3	10,136.0	(4,580.7)
AEP	150,919.5	123,857.8	27,061.6	161,454.9	129,456.2	31,998.6
APS	47,076.4	47,281.8	(205.3)	47,064.4	49,927.1	(2,862.7)
ATSI	40,233.7	65,348.0	(25,114.4)	40,214.6	67,523.0	(27,308.4)
BGE	19,957.3	30,279.0	(10,321.7)	21,167.4	31,641.8	(10,474.4)
ComEd	128,205.5	94,325.9	33,879.5	132,920.9	97,335.4	35,585.5
DAY	11,555.2	16,848.4	(5,293.2)	4,593.9	17,640.4	(13,046.6)
DEOK	20,082.9	26,267.3	(6,184.3)	19,469.2	27,474.2	(8,005.1)
Dominion	92,302.0	95,358.0	(3,056.0)	96,334.6	100,944.2	(4,609.5)
DPL	7,262.6	17,778.6	(10,516.0)	6,288.8	18,728.5	(12,439.7)
DLCO	16,684.1	13,399.6	3,284.5	15,924.1	13,894.0	2,030.1
EKPC	7,558.9	12,218.3	(4,659.5)	9,094.6	13,232.3	(4,137.6)
JCPL	18,217.2	22,090.8	(3,873.6)	14,793.6	22,844.5	(8,050.9)
Met-Ed	21,915.9	15,046.3	6,869.7	22,777.5	15,766.8	7,010.8
OVEC	0.0	0.0	0.0	1,091.2	11.9	1,079.2
PECO	63,483.9	39,296.8	24,187.1	66,905.3	40,579.9	26,325.4
PENELEC	43,413.5	16,757.9	26,655.6	42,903.1	17,322.1	25,581.0
Pepco	8,532.6	29,205.5	(20,672.9)	12,348.3	30,176.7	(17,828.4)
PPL	48,872.5	39,470.6	9,401.9	57,333.9	41,016.7	16,317.2
PSEG	43,991.4	42,788.0	1,203.3	47,274.7	43,956.8	3,317.8
RECO	0.0	1,432.6	(1,432.6)	0.0	1,484.5	(1,484.5)

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

Demand

Demand includes physical load and exports and virtual transactions.

Peak Demand

In this section, demand refers to accounting load and exports and in the Day-Ahead Energy Market also includes virtual transactions.[44]

The PJM system real-time peak load in 2018 was 147,042 MWh in the HE 1700 on August 28, 2018, which was 4,656 MWh, or 3.3 percent, higher than the peak load in 2017, which was 142,387 MWh in the HE 1800 on July 19, 2017.

Table 3-17 shows the peak loads for 2008 through 2018.

Table 3-17 Actual footprint peak loads: 2008 to 2018[45 46]

	Date	Hour Ending (EPT)	PJM Load (MW)	Annual Change (MW)	Annual Change (%)
2008	Fri, August 01	17	122,215	NA	NA
2009	Mon, August 10	17	123,900	1,686	1.4%
2010	Tue, July 06	17	133,297	9,397	7.6%
2011	Thu, July 21	17	154,095	20,798	15.6%
2012	Tue, July 17	17	150,879	(3,216)	(2.1%)
2013	Thu, July 18	17	153,790	2,911	1.9%
2014	Tue, June 17	18	138,448	(15,341)	(10.0%)
2015	Tue, July 28	17	140,266	1,818	1.3%
2016	Thu, August 11	16	148,577	8,311	5.9%
2017	Wed, July 19	18	142,387	(6,190)	(4.2%)
2018	Tue, August 28	17	147,042	4,656	3.3%

Figure 3-18 shows the peak loads for 2008 through 2018.

Figure 3-18 Footprint calendar year peak loads: 2008 to 2018

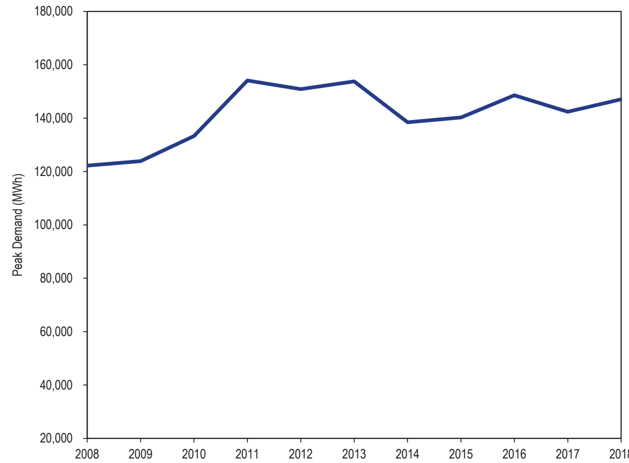
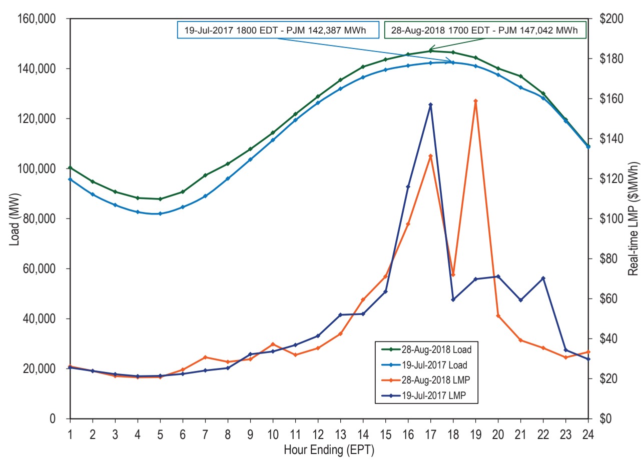


Figure 3-19 compares the peak load days of 2017 and 2018. The average real-time LMP for the August 28, 2018 peak load hour was $131.36 and for the July 19, 2017 peak load hour was $59.49.

Figure 3-19 Peak-load comparison Wednesday, July 19, 2017 and Tuesday, August 28, 2018



Real-Time Demand

PJM average real-time demand in 2018 increased by 4.3 percent from 2017, from 86,618 MWh to 90,307 MWh.[47]

PJM average real-time demand including exports in 2018 increased by 3.7 percent from 2017, from 91,015 MWh to 94,351 MWh.

44 PJM reports peak load including accounting load plus an addback equal to PJM's estimated load drop from demand side resources. This will generally result in PJM reporting peak load values greater than accounting load values. PJM's load drop estimate is based on PJM Manual 19: Load Forecasting and Analysis," Attachment A: Load Drop Estimate Guidelines at <http://www.pjm.com/~/media/documents/manuals/m19.ashx>.

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

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

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

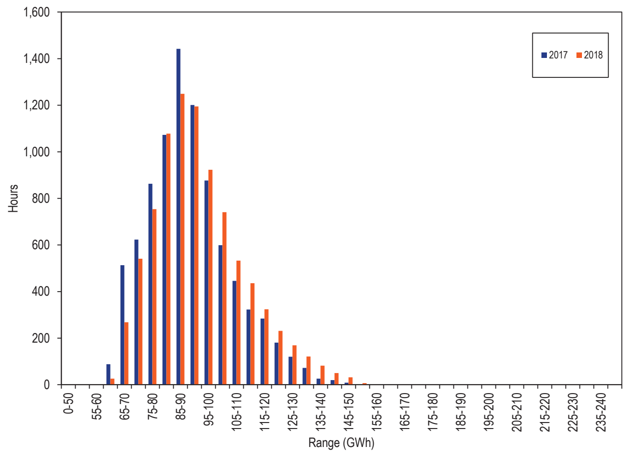
In the PJM Real-Time Energy Market, there are two types of demand:

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

PJM Real-Time Demand Duration

Figure 3-20 shows the hourly distribution of PJM real-time load plus exports for 2017 and 2018.[48]

Figure 3-20 Distribution of real-time accounting load plus exports: 2017 and 2018[49]



PJM Real-Time, Average Load

Table 3-18 presents summary average real-time hourly demand statistics for 2001 to 2018. Before June 1, 2007, transmission losses were included in accounting load. After June 1, 2007, transmission losses were excluded from accounting load and losses were addressed through marginal loss pricing.[50]

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

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

50 Accounting load is used here because PJM uses accounting load in the settlement process, which determines how much load customers pay for. In addition, the use of accounting load with losses before June 1, and without losses after June 1, 2007, is consistent with PJM's calculation of LMP, which excluded losses prior to June 1 and includes losses after June 1.

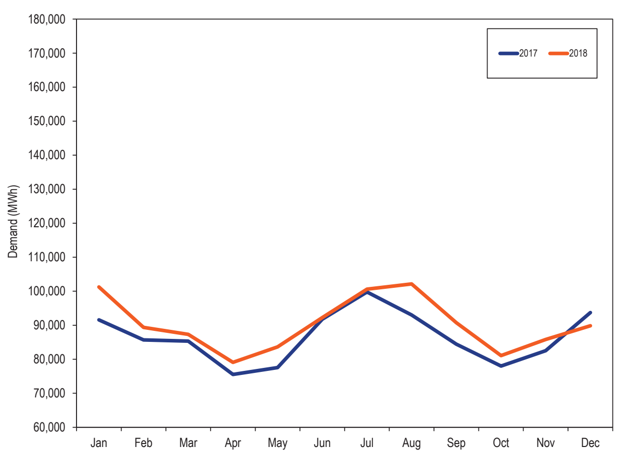
Table 3-18 Real-time load and real-time load plus exports: 2001 through 2018

	PJM Real-Time Demand (MWh)				Year-to-Year Change			
	Load		Load Plus Exports		Load		Load Plus Exports	
	Load	Standard Deviation	Demand	Standard Deviation	Load	Standard Deviation	Demand	Standard Deviation
2001	30,297	5,873	32,165	5,564	NA	NA	NA	NA
2002	35,776	7,976	37,676	8,145	18.1%	35.8%	17.1%	46.4%
2003	37,395	6,834	39,380	6,716	4.5%	(14.3%)	4.5%	(17.5%)
2004	49,963	13,004	54,953	14,947	33.6%	90.3%	39.5%	122.6%
2005	78,150	16,296	85,301	16,546	56.4%	25.3%	55.2%	10.7%
2006	79,471	14,534	85,696	15,133	1.7%	(10.8%)	0.5%	(8.5%)
2007	81,681	14,618	87,897	15,199	2.8%	0.6%	2.6%	0.4%
2008	79,515	13,758	86,306	14,322	(2.7%)	(5.9%)	(1.8%)	(5.8%)
2009	76,034	13,260	81,227	13,792	(4.4%)	(3.6%)	(5.9%)	(3.7%)
2010	79,611	15,504	85,518	15,904	4.7%	16.9%	5.3%	15.3%
2011	82,541	16,156	88,466	16,313	3.7%	4.2%	3.4%	2.6%
2012	87,011	16,212	92,135	16,052	5.4%	0.3%	4.1%	(1.6%)
2013	88,332	15,489	92,879	15,418	1.5%	(4.5%)	0.8%	(3.9%)
2014	89,099	15,763	94,471	15,677	0.9%	1.8%	1.7%	1.7%
2015	88,594	16,663	92,665	16,784	(0.6%)	5.7%	(1.9%)	7.1%
2016	88,601	17,229	93,551	17,498	0.0%	3.4%	1.0%	4.3%
2017	86,618	15,170	91,015	15,083	(2.2%)	(11.9%)	(2.7%)	(13.8%)
2018	90,307	15,982	94,351	16,142	4.3%	5.4%	3.7%	7.0%

PJM Real-Time, Monthly Average Load

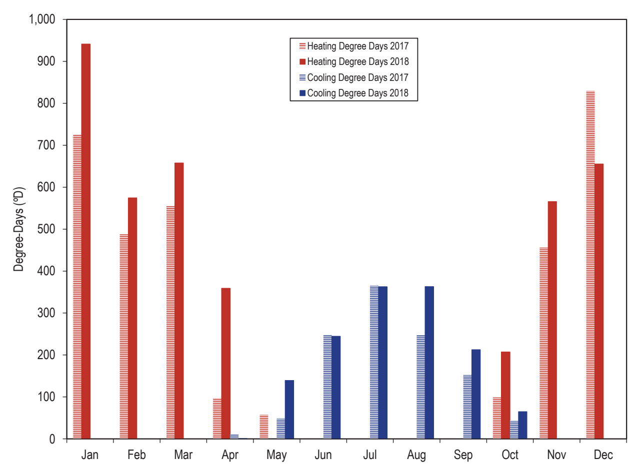
Figure 3-21 compares the real-time, monthly average hourly loads for 2017 and 2018.

Figure 3-21 Real-time monthly average hourly load: 2017 through 2018



PJM real-time load is significantly affected by temperature. Figure 3-22 and Table 3-19 compare the PJM monthly heating and cooling degree days in 2017 and 2018.[51] Heating degree days increased 19.7 percent from 2017 to 2018. Cooling degree days increased by 24.2 percent.

Figure 3-22 Heating and cooling degree days: 2017 through 2018



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

Table 3-19 Heating and cooling degree days: 2017 through 2018

	2017		2018		Percent Change	
	Heating Degree Days	Cooling Degree Days	Heating Degree Days	Cooling Degree Days	Heating Degree Days	Cooling Degree Days
Jan	725	0	941	0	29.7%	0.0%
Feb	488	0	575	0	17.8%	0.0%
Mar	555	0	658	0	18.5%	0.0%
Apr	97	11	359	1	268.9%	(90.7%)
May	58	49	0	139	(100.0%)	184.6%
Jun	0	249	0	245	0.0%	(1.6%)
Jul	0	366	0	363	0.0%	(0.8%)
Aug	0	248	0	363	0.0%	46.6%
Sep	1	152	0	213	(100.0%)	39.5%
Oct	99	44	207	65	109.0%	48.0%
Nov	456	0	566	0	24.0%	0.0%
Dec	830	0	655	0	(21.0%)	0.0%
Total	3,309	1,118	3,961	1,389	19.7%	24.2%

Day-Ahead Demand

PJM average day-ahead demand in 2018, including DECs and up to congestion transactions, decreased by 12.5 percent from 2017, from 125,792 MWh to 110,091 MWh.

PJM average day-ahead demand in 2018, including DECs, up to congestion transactions, and exports, decreased by 12.3 percent from of 2017, from 128,755 MWh to 112,885 MWh.

The significant decrease in up to congestion transactions (UTC) is a result of the reduction in the number of UTC trading points as directed in the FERC order issued February 20, 2018.[52]

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

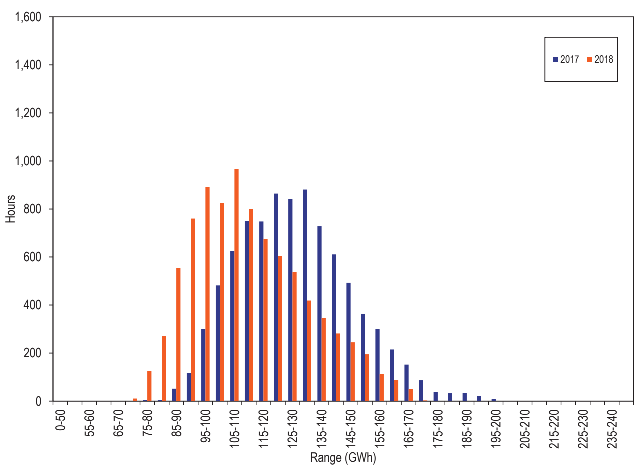
- **Fixed-Demand Bid.** Bid to purchase a defined MWh level of energy, regardless of LMP.
- **Price-Sensitive Bid.** Bid to purchase a defined MWh level of energy only up to a specified LMP, above which the load bid is zero.
- **Decrement Bid (DEC).** Financial bid to purchase a defined MWh level of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

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

PJM Day-Ahead Demand Duration

Figure 3-23 shows the hourly distribution of PJM day-ahead demand, including decrement bids, up to congestion transactions, and exports for 2017 and 2018.

Figure 3-23 Distribution of day-ahead demand plus exports: 2017 and 2018[53]



52 162 FERC ¶ 61,139.

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

PJM Day-Ahead, Average Demand

Table 3-20 presents summary average day-ahead hourly demand statistics for each year from 2001 to 2018.

Table 3-20 Average hourly day-ahead demand and day-ahead demand plus exports: 2001 through 2018

	PJM Day-Ahead Demand (MWh)				Year-to-Year Change			
	Demand		Demand Plus Exports		Demand		Demand Plus Exports	
	Demand	Standard Deviation	Demand	Standard Deviation	Demand	Standard Deviation	Demand	Standard Deviation
2001	33,370	6,562	33,757	6,431	NA	NA	NA	NA
2002	42,305	10,161	42,413	10,208	26.8%	54.8%	25.6%	58.7%
2003	44,674	7,841	44,807	7,811	5.6%	(22.8%)	5.6%	(23.5%)
2004	62,101	16,654	63,455	17,730	39.0%	112.4%	41.6%	127.0%
2005	93,534	17,643	96,447	17,952	50.6%	5.9%	52.0%	1.3%
2006	98,527	16,723	101,592	17,197	5.3%	(5.2%)	5.3%	(4.2%)
2007	105,503	16,686	108,932	17,030	7.1%	(0.2%)	7.2%	(1.0%)
2008	101,903	15,871	105,368	16,119	(3.4%)	(4.9%)	(3.3%)	(5.3%)
2009	94,941	15,869	98,094	15,999	(6.8%)	(0.0%)	(6.9%)	(0.7%)
2010	103,937	21,358	108,069	21,640	9.5%	34.6%	10.2%	35.3%
2011	113,866	20,708	117,681	20,929	9.6%	(3.0%)	8.9%	(3.3%)
2012	131,612	17,421	134,947	17,527	15.6%	(15.9%)	14.7%	(16.3%)
2013	144,858	18,489	148,132	18,570	10.1%	6.1%	9.8%	6.0%
2014	142,251	32,664	146,120	32,671	(1.8%)	76.7%	(1.4%)	75.9%
2015	111,644	18,716	114,827	18,872	(21.5%)	(42.7%)	(21.4%)	(42.2%)
2016	127,374	21,513	130,808	21,803	14.1%	14.9%	13.9%	15.5%
2017	125,794	19,402	128,757	19,625	(1.2%)	(9.8%)	(1.6%)	(10.0%)
2018	110,091	19,521	112,885	19,724	(12.5%)	0.6%	(12.3%)	0.5%

PJM Day-Ahead, Monthly Average Demand

Figure 3-24 compares the day-ahead, monthly average hourly demand, including decrement bids and up to congestion transactions in 2017 and 2018.

Figure 3-24 Day-ahead monthly average hourly demand: 2017 through 2018

Real-Time and Day-Ahead Demand

Table 3-21 presents summary statistics for 2017 and 2018 day-ahead and real-time demand. All data are cleared MW. The last two columns of Table 3-21 are the day-ahead demand minus the real-time demand. The first such column is the total day-ahead demand less the total real-time demand and the second such column is the total physical day-ahead load (fixed demand plus price-sensitive demand) less the physical real-time load.

Table 3-21 Cleared day-ahead and real-time demand (MWh): 2017 and 2018

		Day-Ahead						Real-Time		Day-Ahead Less Real-Time	
	Year	Fixed Demand	Price Sensitive	DEC Bids	Up-to Congestion	Exports	Total Demand	Load	Total Demand	Total Demand	Total Load
Average	2017	83,959	2,871	4,035	34,927	2,963	128,755	86,618	91,015	37,740	211
	2018	87,506	2,055	2,906	17,624	2,794	112,885	90,307	94,351	18,535	(747)
Median	2017	82,645	2,847	4,006	33,823	2,875	127,506	84,875	89,206	38,299	617
	2018	85,619	1,908	2,634	16,453	2,721	109,878	88,043	91,910	17,968	(516)
Standard Deviation	2017	14,567	437	1,401	8,226	997	19,625	15,170	15,083	4,543	(166)
	2018	15,194	611	1,377	7,210	961	19,724	15,982	16,142	3,582	(177)
Peak Average	2017	92,686	3,157	4,276	37,172	2,985	140,276	95,148	99,449	40,827	696
	2018	96,269	2,266	3,196	18,590	2,892	123,213	98,857	102,847	20,366	(322)
Peak Median	2017	89,866	3,099	4,347	36,106	2,883	138,149	91,910	96,151	41,998	1,054
	2018	93,916	2,007	2,946	17,163	2,798	120,825	95,900	99,805	21,020	23
Peak Standard Deviation	2017	12,247	384	1,365	8,162	1,057	16,530	13,230	13,247	3,283	(599)
	2018	12,918	618	1,371	7,633	966	17,645	14,118	14,513	3,133	(582)
Off-Peak Average	2017	76,406	2,623	3,827	32,985	2,944	118,784	79,237	83,716	35,068	(209)
	2018	79,866	1,871	2,653	16,783	2,709	103,882	82,854	86,943	16,939	(1,117)
Off-Peak Median	2017	74,546	2,573	3,692	31,925	2,872	116,239	77,160	81,561	34,678	(41)
	2018	77,971	1,620	2,364	15,774	2,649	100,165	80,633	84,518	15,647	(1,042)
Off-Peak Standard Deviation	2017	11,963	310	1,398	7,775	943	16,363	12,664	12,557	3,806	(392)
	2018	12,701	542	1,331	6,708	949	16,815	13,604	13,650	3,165	(360)

Figure 3-25 shows the average hourly cleared volumes of day-ahead demand and real-time demand for 2018. The day-ahead demand includes day-ahead load, day-ahead exports, decrement bids and up to congestion transactions. The real-time demand includes real-time load and real-time exports.

Figure 3-25 Day-ahead and real-time demand (Average hourly volumes): 2018

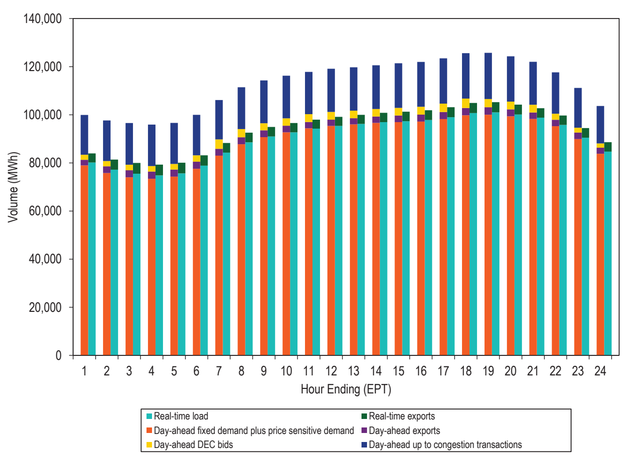
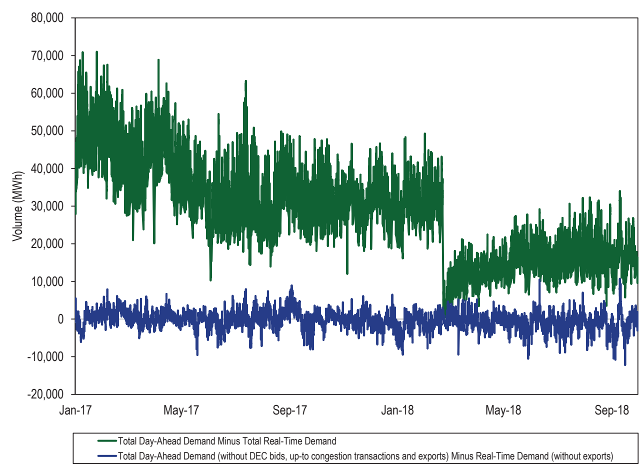


Figure 3-26 shows the difference between the day-ahead and real-time average daily demand for 2017 and 2018.

Figure 3-26 Difference between day-ahead and real-time demand (Average daily volumes): 2017 through 2018



Supply and Demand: Load and Spot Market

Real-Time Load and Spot Market

Participants in the PJM Real-Time Energy Market can use their own generation to meet load, to sell in the bilateral market or to sell in the spot market in any hour. Participants can both buy and sell via bilateral contracts and buy and sell in the spot market in any hour. If a participant has positive net bilateral transactions in an hour, it is buying energy through bilateral contracts (bilateral purchase). If a participant has negative net bilateral transactions in an hour, it is selling energy through bilateral contracts (bilateral sale). If a participant has positive net spot transactions in an hour, it is buying energy from the spot market (spot purchase). If a participant has negative net spot transactions in an hour, it is selling energy to the spot market (spot sale).

Real-time load is served by a combination of self-supply, bilateral market purchases and spot market purchases. From the perspective of a parent company of a PJM billing organization that serves load, its load could be supplied by any combination of its own generation, net bilateral market purchases and net spot market purchases. In addition to directly serving load, load serving entities can also transfer their responsibility to serve load to other parties through eSchedules transactions referred to as wholesale load responsibility (WLR) or retail load responsibility (RLR) transactions. When the responsibility to serve load is transferred via a bilateral contract, the entity to which the responsibility is transferred becomes the load serving entity. Supply from its own generation (self-supply) means that the parent company is generating power from plants that it owns in order to meet demand. Supply from bilateral purchases means that the parent company is purchasing power under bilateral contracts from a nonaffiliated company at the same time that it is meeting load. Supply from spot market purchases means that the parent company is generating less power from owned plants and/or purchasing less power under bilateral contracts than required to meet load at a defined time and, therefore, is purchasing the required balance from the spot market.

The PJM system's reliance on self-supply, bilateral contracts and spot purchases to meet real-time load is calculated by summing across all the parent companies of PJM billing organizations that serve load in the Real-Time Energy Market for each hour. Table 3-22 shows the monthly average share of real-time load served by self-supply, bilateral contracts and spot purchase in 2017 and 2018 based on parent company. In 2018, 13.5 percent of real-time load was supplied by bilateral contracts, 28.8 percent by spot market purchase and 58.8 percent by self-supply. Compared with 2017, reliance on bilateral contracts decreased by 0.9 percentage points, reliance on spot supply increased by 1.3 percentage points and reliance on self-supply decreased by 0.1 percentage points.

Table 3-22 Sources of real-time supply: 2017 and 2018[54]

	2017			2018			Difference in Percentage Points		
	Bilateral Contract	Spot	Self-Supply	Bilateral Contract	Spot	Self-Supply	Bilateral Contract	Spot	Self-Supply
Jan	15.6%	23.1%	61.3%	11.8%	29.8%	59.4%	(3.7%)	6.6%	(1.9%)
Feb	16.8%	22.9%	60.3%	13.5%	29.1%	58.5%	(3.3%)	6.2%	(1.9%)
Mar	14.0%	25.3%	60.7%	12.0%	31.8%	57.2%	(2.0%)	6.5%	(3.5%)
Apr	13.0%	26.9%	60.1%	13.1%	30.2%	57.7%	0.1%	3.3%	(2.4%)
May	13.3%	25.1%	62.3%	12.6%	29.8%	58.6%	(0.6%)	4.7%	(3.7%)
Jun	13.3%	28.0%	59.9%	12.6%	28.5%	60.0%	(0.6%)	0.5%	0.1%
Jul	15.0%	26.9%	59.5%	13.7%	28.3%	59.4%	(1.2%)	1.3%	(0.1%)
Aug	15.5%	26.3%	59.6%	11.8%	29.0%	60.6%	(3.7%)	2.7%	1.1%
Sep	14.0%	30.0%	57.2%	13.6%	30.1%	57.6%	(0.4%)	0.1%	0.4%
Oct	13.4%	30.3%	57.3%	15.1%	26.7%	59.3%	1.6%	(3.6%)	2.0%
Nov	13.5%	31.1%	56.4%	14.4%	29.5%	57.2%	0.9%	(1.6%)	0.8%
Dec	15.4%	33.4%	52.3%	18.5%	23.1%	59.5%	3.1%	(10.3%)	7.2%
Annual	14.4%	27.5%	58.9%	13.5%	28.8%	58.8%	(0.9%)	1.3%	(0.1%)

Day-Ahead Load and Spot Market

In the PJM Day-Ahead Energy Market, participants can not only use their own generation, bilateral contracts and spot market purchases to supply their load serving obligation, but can also use virtual resources to meet their load serving obligations in any hour. Virtual supply is treated as supply in the day-ahead analysis and virtual demand is treated as demand in the day-ahead analysis.

The PJM system's reliance on self-supply, bilateral contracts, and spot purchases to meet day-ahead demand (cleared fixed-demand, price-sensitive load and decrement bids) is calculated by summing across all the parent companies of PJM billing organizations that serve demand in the Day-Ahead Energy Market for each hour. Table 3-23 shows the monthly average share of day-ahead demand served by self-supply, bilateral contracts and spot purchases in 2017 and 2018, based on parent companies. In 2018, 10.1 percent of day-ahead demand was supplied by bilateral contracts, 30.7 percent by spot market purchases and 59.2 percent by self-supply. Compared with 2017, reliance on bilateral contracts decreased by 1.4 percentage points, reliance

54 Table 3-22 and Table 3-23 were calculated as of January 18, 2019. The values may change slightly as billing values are updated by PJM.

on spot supply increased by 1.8 percentage points, and reliance on self-supply decreased by 0.4 percentage points.

Table 3-23 Sources of day-ahead supply: 2017 and 2018

	2017			2018			Difference in Percentage Points		
	Bilateral Contract	Spot	Self-Supply	Bilateral Contract	Spot	Self-Supply	Bilateral Contract	Spot	Self-Supply
Jan	13.5%	24.1%	62.4%	9.2%	31.9%	58.9%	(4.3%)	7.8%	(3.5%)
Feb	14.0%	25.3%	60.7%	10.2%	31.3%	58.5%	(3.9%)	6.0%	(2.2%)
Mar	11.4%	27.6%	61.0%	9.1%	32.8%	58.1%	(2.3%)	5.2%	(3.0%)
Apr	10.7%	28.7%	60.6%	9.9%	31.9%	58.2%	(0.8%)	3.2%	(2.3%)
May	10.2%	27.5%	62.3%	9.4%	31.5%	59.1%	(0.9%)	4.0%	(3.1%)
Jun	10.7%	29.3%	60.1%	9.4%	29.8%	60.8%	(1.2%)	0.5%	0.7%
Jul	11.4%	29.3%	59.3%	10.6%	29.3%	60.2%	(0.8%)	(0.0%)	0.8%
Aug	11.8%	28.9%	59.3%	8.6%	30.4%	61.0%	(3.2%)	1.5%	1.7%
Sep	11.0%	31.6%	57.4%	10.5%	31.4%	58.1%	(0.5%)	(0.2%)	0.7%
Oct	10.5%	32.2%	57.3%	11.2%	29.5%	59.2%	0.8%	(2.6%)	1.9%
Nov	10.6%	33.0%	56.4%	11.0%	32.1%	57.0%	0.4%	(0.9%)	0.6%
Dec	12.3%	29.5%	58.2%	13.0%	27.0%	60.1%	0.7%	(2.6%)	1.9%
Annual	11.5%	28.9%	59.6%	10.1%	30.7%	59.2%	(1.4%)	1.8%	(0.4%)

Internal Bilateral Transactions

Internal bilateral transactions (IBTs) transfer the title of an energy injection from a seller to a buyer at a specified pnode. For market participants IBTs allow market participants to avoid bilateral contracts. For example, an LSE may have a bilateral contract with a generator for the purchase of power at a fixed price to be delivered at the zone where the LSE is located. Absent an IBT the LSE would need a bilateral contract with the generator to avoid paying both the generator and PJM for the power consumed. Similarly, the merchant generator would also need the bilateral contract to avoid being paid twice for the power, once by the LSE and once by PJM. In order to avoid the bilateral contract, the LSE and the merchant generator can submit an IBT with the LSE as the buyer and the merchant generator as the seller with the source and sink pnode at the zone where the LSE is serving load. The LSE receives a credit equivalent to the price of the IBT MWh while the merchant generator receives a charge equivalent to the price of the IBT MWh. By reporting bilateral transactions to PJM through IBTs market participants avoid a bilateral contract and the credit requirements associated with the contract.

IBTs are not part of the day-ahead unit commitment process, do not set energy prices, and do not impact energy flows in either the day-ahead or real-time markets. However, prior to November 1, 2018, real-time IBTs incurred a balancing operating reserve deviation charge for both the buyer and the seller. Day-ahead IBTs do not incur a balancing operating reserve deviation charge as PJM automatically creates a real-time MW position to offset the day-ahead position. Market participants used a day-ahead virtual position at the same location to offset the operating reserve deviation charge incurred by real-time IBTs. The buyer of the IBT used an INC as the offsetting position INC and the seller used a DEC.

In 2011, market participants who were inappropriately using IBTs with subsidiaries in order to offset the deviations incurred by the trading of INCs and DECs and to avoid paying balancing operating reserve charges were notified that their bills would be adjusted.[55] On September 6, 2018, the Commission approved tariff changes to revise the allocation of operating reserves and to exclude IBTs from the calculation of deviations for the allocation of uplift.[56] PJM explained, "allowing bilateral transactions to impact the calculation of supply and demand deviations would allow Market Participants to artificially decrease the amount of uplift they are allocated by using them in a manner to purposefully accomplish this goal."[57]

Beginning on November 1, 2018, real-time priced IBTs are no longer assessed deviations. The volume of real-time IBTs collapsed beginning around January 2018 and there are no longer virtual transactions associated with real-time priced IBT offsets. The incremental market impact from this rule change is expected to be negligible.

Through the end of 2017 market participants used a large volume of INCs and DECs for these IBT offsets. Figure 3-27 shows the sum by month of real-time MW by IBT sellers and the sum of cleared DEC MW by sellers of real-time IBTs at the same location and hour. Figure 3-28 shows the sum by month of real-time MW by IBT buyers and the sum of cleared INC MW by buyers of real-time IBTs at the same location and hour.

55 A participant filed a complaint seeking to avoid rebilling, but it was denied. See 138 FERC ¶ 61,165 at P65, Order Denying Complaint, *reh'g denied*, 144 FERC ¶ 61,024 (2012).

56 FERC Docket No. ER18-86-000. 162 FERC ¶ 61,019, *order granting reh'g in part*, 164 FERC ¶ 61,168 at P 16 (Sept. 6, 2018).

57 PJM filing, FERC Docket No. ER18-86-000 (Nov. 17, 2017) at 12.

Figure 3-27 and Figure 3-28 also show the volume of these offset transactions as a share of all INCs and DECs. The analysis shows that these transactions made up over 50 percent all INC and DEC volume. The large drop in INC and DEC volumes beginning in November 2017 was the result of decreasing volumes of real-time IBTs. In 2018, the volume of real-time priced IBTs decreased significantly. There have been no INC and DEC transactions associated with real-time IBT offsets since May 2018.

Figure 3-27 Real-time priced IBTs and offset DEC MW by IBT sellers: 2013 through 2018

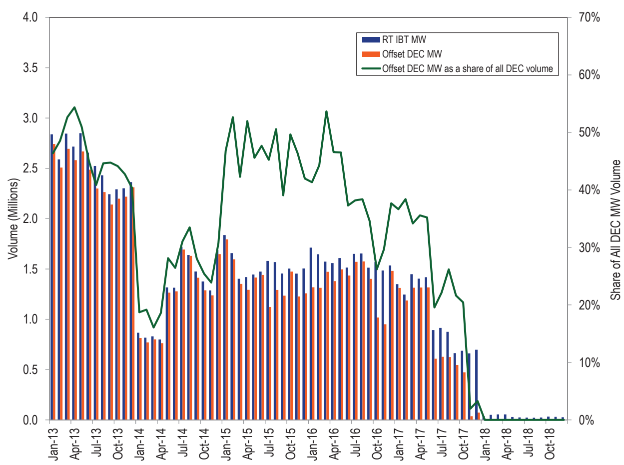
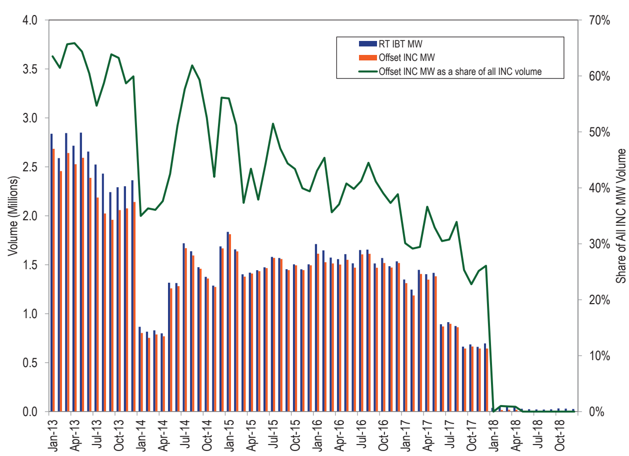


Figure 3-28 Real-time priced IBTs and offset INC MW by IBT buyers: 2013 through 2018



Market Behavior

Local Market Power

In the PJM energy market, market power mitigation rules currently apply only for local market power. Local market power exists when transmission constraints or reliability issues create local markets that are structurally noncompetitive. If the owners of the units required to solve the constraint or reliability issue are pivotal or jointly pivotal, they have the ability to set the price. Absent market power mitigation, unit owners that submit noncompetitive offers, or offers with inflexible operating parameters, could exercise market power. This could result in LMPs being set at higher than competitive levels, or could result in noncompetitive uplift payments.

The three pivotal supplier (TPS) test is the test for local market power in the energy market.[58] If the TPS is failed, market power mitigation is implemented by offer capping the resources of the owners who have local market power. Offer capping is designed to set offers at competitive levels. Competitive offers are defined to be cost-based energy offers. In the PJM energy market, units are required to submit cost-based energy offers, defined by fuel cost policies, and have the option to submit market-based or price-based offers. Units are committed and dispatched on price-based offers, if offered, as the default offer. When a unit that submits both cost-based and price-based offers is mitigated to its cost-based offer by PJM, it is considered offer capped. A unit that submits only cost-based offers, or that requests PJM to dispatch it on its cost-based offer, is not considered offer capped.

TPS Test Statistics for Local Market Power

The TPS test in the energy market defines whether one, two or three suppliers are jointly pivotal in a defined local market. The TPS test is applied every time the system solution indicates that out of merit resources are needed to relieve a transmission constraint. The TPS test result for a constraint for a specific interval indicates whether a supplier failed or passed the test for that constraint for that interval. A failed test indicates that the resource owner has structural market power.

58 See the MMU Technical Reference for PJM Markets, at "Three Pivotal Supplier Test" for a more detailed explanation of the three pivotal supplier test. <http://www.monitoringanalytics.com/reports/Technical_References/references.shtml>.

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

In 2018, the AECO, AEP, APS, ATSI, BGE, ComEd, Dominion, DPL, EKPC, Met-Ed, PECO, PENELEC, PPL and PSEG control zones experienced congestion resulting from one or more constraints binding for 100 or more hours or resulting from an interface constraint (Table 3-24). The DAY, DEOK, DLCO, JCPL, OVEC, Pepco, and RECO control zones did not have constraints binding for 100 or more hours in 2018. Table 3-24 shows that BGE, ComEd, PPL and PSEG were the control zones that experienced congestion resulting from one or more constraints binding for 100 or more hours or resulting from an interface constraint that was binding for one or more hours in every year from 2009 through 2018. The constrained hours in the AEP Zone increased from 469 hours in 2017 to 1,878 hours in 2018 as a result of increased constraint hours for Tanners Creek - Miami Fort, Capitol Hill – Chemical, and Cloverdale due to cold weather related demand in January 2018. The constrained hours in the Met-Ed Zone increased from 116 hours in 2017 to 1,559 hours in 2018 as a result of outages at the Hunterstown station. The constrained hours in the PECO Zone decreased from 1,013 hours in 2017 to 304 hours in 2018 due to completion of outages at the Emilie substation.

Table 3-24 Congestion hours resulting from one or more constraints binding for 100 or more hours or from an interface constraint: 2009 through 2018

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
AECO	149	172	234	0	208	0	394	439	0	500
AEP	1,045	1,636	2,510	0	2,611	2,710	1,274	796	469	1,878
APS	509	1,714	0	206	0	170	167	0	265	246
ATSI	157	0	0	208	270	489	242	141	1,113	2,856
BGE	152	470	1,041	2,970	1,760	6,255	9,601	11,434	2,178	3,135
ComEd	1,212	2,080	1,134	4,554	5,143	4,119	5,878	7,336	2,257	1,148
DEOK	0	0	0	109	0	0	112	0	0	0
DLCO	156	475	206	209	0	223	617	0	0	0
Dominion	468	905	1,179	1,020	664	0	1,172	459	436	136
DPL	0	122	0	1,542	639	3,071	2,066	2,719	673	1,117
EKPC	0	0	0	0	0	0	0	0	0	400
Met-Ed	0	180	162	0	0	0	222	0	116	1,559
PECO	247	0	788	386	732	1,953	895	692	1,013	304
PENELEC	103	284	0	0	176	4,281	1,683	451	3,074	1,648
Pepco	149	1	0	143	245	41	0	0	0	0
PPL	176	118	40	350	452	148	266	936	2,044	436
PSEG	303	549	1,107	913	3,021	4,688	2,665	810	239	226

The local market structure in the Real-Time Energy Market associated with each of the frequently binding constraints was analyzed using the three pivotal supplier results in 2018.[59] While the real-time constraint hours include constraints that were binding in the five minute real-time pricing solution (LPC), IT SCED may contain different binding constraints because IT SCED looks ahead to intervals that are in the near future to solve for constraints that could be binding, using the load forecast for these intervals. The TPS statistics shown in this section present the data from the IT SCED TPS solution. The results of the TPS test are shown for tests that could have resulted in offer capping and tests that resulted in offer capping.

The results confirm that the three pivotal supplier test results in offer capping when the local market is structurally noncompetitive and does not result in offer capping when that is not the case.

Table 3-25 shows the average constraint relief required on the constraint, the average effective supply available to relieve the constraint, the average number of owners with available relief in the defined market and the average number of owners passing and failing for the transfer interface constraints. Table 3-25 includes analysis of all the tests for every interval where IT SCED determined that constraint relief was needed for each of the constraints shown. The same interval can be evaluated by multiple IT SCED cases at different look ahead times.

59 See the *MMU Technical Reference for PJM Markets*, at "Three Pivotal Supplier Test" for a more detailed explanation of the three pivotal supplier test. <http://www.monitoringanalytics.com/reports/Technical_References/references.shtml>.

Table 3-25 Three pivotal supplier test details for interface constraints: 2018

Constraint	Period	Average Constraint Relief (MW)	Average Effective Supply (MW)	Average Number Owners	Average Number Owners Passing	Average Number Owners Failing
5004/5005 Interface	Peak	398	326	10	0	10
	Off Peak	631	465	11	0	11
AEP - DOM	Peak	466	343	9	0	9
	Off Peak	632	541	12	0	12
AP South	Peak	291	542	15	3	12
	Off Peak	258	494	16	6	10
Bedington - Black Oak	Peak	184	125	9	0	9
	Off Peak	201	130	10	0	10
CPL - DOM	Peak	225	314	8	1	8
	Off Peak	142	254	7	0	7
East	Peak	NA	NA	NA	NA	NA
	Off Peak	293	223	6	0	6
West	Peak	269	191	9	0	9
	Off Peak	300	362	12	0	12

The three pivotal supplier test is applied every time the IT SCED solution indicates that incremental relief is needed to relieve a transmission constraint. While every system solution that requires incremental relief to transmission constraints will result in a test, not all tested providers of effective supply are eligible for offer capping. Steam units that are offer capped in the Day-Ahead Energy Market continue to be offer capped in the Real-Time Energy Market regardless of their inclusion in the TPS test in real time and the outcome of the TPS test in real time. Offline units that are committed to provide relief for a transmission constraint, whose owners fail the TPS test, are committed on the cheaper of their cost or price-based offers. Beginning November 1, 2017, with the introduction of hourly offers and intraday offer updates, certain online units whose commitment is extended beyond the day-ahead or real-time commitment, whose owners fail the TPS test, are also switched to the cost-based offer if it is cheaper than the price-based offer. Table 3-26 provides, for the identified interface constraints, information on total tests applied, the subset of three pivotal supplier tests that could have resulted in offer capping and the portion of those tests that did result in offer capping. The three pivotal supplier tests that resulted in offer capping do not explain all the offer capped units in the Real-Time Energy Market. PJM operators also manually commit units for reliability reasons other than providing relief to a binding constraint.

Table 3-26 Summary of three pivotal supplier tests applied for interface constraints: 2018

Constraint	Period	Total Tests Applied	Total Tests that Could Have Resulted in Offer Capping	Percent Total Tests that Could Have Resulted in Offer Capping	Total Tests Resulted in Offer Capping	Percent Total Tests Resulted in Offer Capping	Tests Resulted in Offer Capping as Percent of Tests that Could Have Resulted in Offer Capping
5004/5005 Interface	Peak	829	829	100%	14	2%	2%
	Off Peak	844	836	99%	22	3%	3%
AEP - DOM	Peak	2,182	2,172	100%	38	2%	2%
	Off Peak	3,342	3,341	100%	97	3%	3%
AP South	Peak	200	198	99%	3	2%	2%
	Off Peak	144	143	99%	10	7%	7%
Bedington - Black Oak	Peak	516	508	98%	0	0%	0%
	Off Peak	670	664	99%	12	2%	2%
CPL - DOM	Peak	1,535	1,504	98%	14	1%	1%
	Off Peak	1,120	1,119	100%	2	0%	0%
East	Peak	NA	NA	NA	NA	NA	NA
	Off Peak	38	29	76%	0	0%	0%
West	Peak	63	63	100%	0	0%	0%
	Off Peak	185	179	97%	0	0%	0%

Offer Capping for Local Market Power

In the PJM energy market, offer capping occurs as a result of structurally noncompetitive local markets and noncompetitive offers in the Day-Ahead and Real-Time Energy Markets. PJM also uses offer capping for units that are committed for reliability reasons, specifically for providing black start and reactive service as well as for conservative operations. There are no explicit rules governing market structure or the exercise of market power in the aggregate energy market.

The analysis of the application of the three pivotal supplier test demonstrates that it is working for most hours to allow market based offers when the local market structure is competitive and to offer cap owners when the local market structure is noncompetitive. However, there are some issues with the application of mitigation in the Day-Ahead Energy Market and the Real-Time Energy Market when market sellers fail the TPS test. There is no tariff or manual language that defines in detail the application of the TPS test and offer capping in the Day-Ahead Energy Market and the Real-Time Energy Market.

In both the Day-Ahead and Real-Time Energy Markets, generators with market power have the ability to evade mitigation by using varying markups in their price-based offers, offering different operating parameters in their price-based and cost-based offers, and using different fuels in their price-based and cost-based offers. These issues can be resolved by simple rule changes.

When an owner fails the TPS test, the units offered by the owner that are committed to provide relief are committed on the cheaper of cost-based or price-based offers. In the Day-Ahead Energy Market, PJM commits a unit on the schedule that results in the lower overall system production cost. This is consistent with the Day-Ahead Energy Market objective of clearing resources (including physical and virtual resources) to meet the total demand (including physical and virtual demand) at the lowest bid production cost for the system over the 24 hour period. In the Real-Time Energy Market, PJM uses a dispatch cost formula to compare price-based offers and cost-based offers to select the cheaper offer.[60] Prior to the implementation of hourly offers, dispatch cost was calculated as:

$$\{(\text{Incremental Energy Offer@EcoMin} \times \text{EcoMin MW}) + \text{No Load Cost}\} \times \text{Min Run Time} + \text{Start Cost}$$

Beginning November 1, 2017, with hourly differentiated offers, the cheaper of cost and price based offers are determined using total dispatch cost, where:

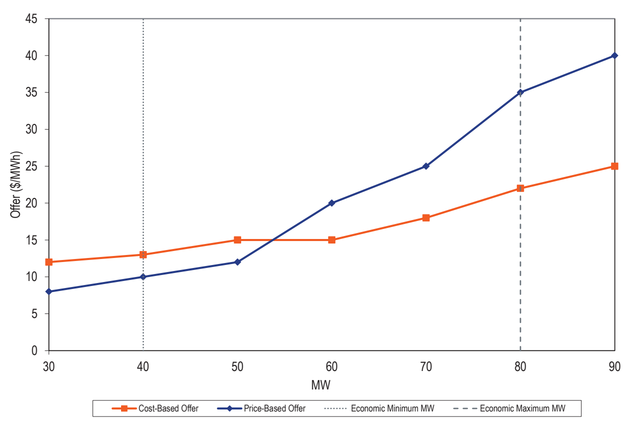
$$\text{Total Dispatch Cost} = \text{Startup Cost} + \sum_{\text{Min Run}} \text{Hourly Dispatch Cost}$$

where the hourly dispatch cost is calculated for each hour using the offers applicable for that hour as:

$$\text{Hourly Dispatch Cost} = (\text{Incremental Energy Offer@EcoMin} \times \text{EcoMin MW}) + \text{NoLoad Cost}$$

With the ability to submit offer curves with varying markups at different output levels in the price-based offer, unit owners with market power can evade mitigation by using a low markup at low output levels and a high markup at higher output levels. Figure 3-29 shows an example of offers from a unit that has a negative markup at the economic minimum MW level and a positive markup at the economic maximum MW level. The result would be that a unit that failed the TPS test would be committed on its price-based offer that has a lower dispatch cost, even though the price-based offer is higher than cost-based offer at higher output levels and includes positive markups, inconsistent with the explicit goal of local market power mitigation.

Figure 3-29 Offers with varying markups at different MW output levels



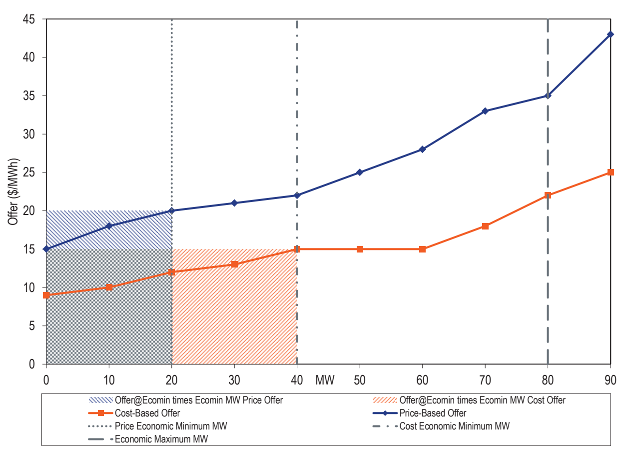
Offering a different economic minimum MW level, different minimum run times, or different start up and notification times in the cost-based and price-based offers can also be used to evade mitigation. For example,

60 See PJM Operating Agreement Schedule 1 § 6.4.1(g).

a unit may offer its price-based offer with a positive markup, but have a shorter minimum run time (MRT) in the price-based offer resulting in a lower dispatch cost for the price-based offer but setting prices at a level that includes a positive markup.

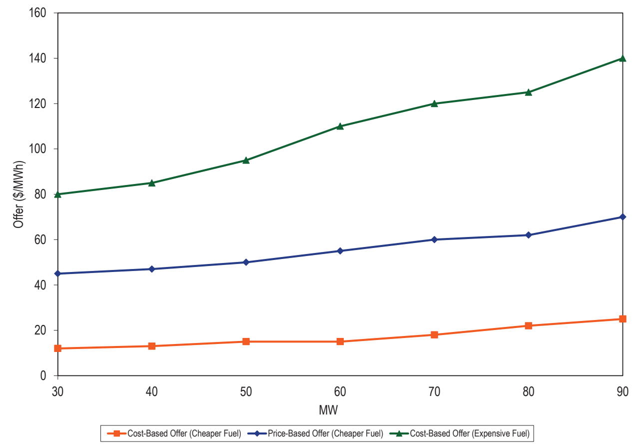
A unit may offer a lower economic minimum MW level on the price-based offer than the cost-based offer. Such a unit may appear to be cheaper to commit on the price-based offer even with a positive markup. A unit with a positive markup can have lower dispatch cost with the price-based offer with a lower economic minimum level compared to cost-based offer. Figure 3-30 shows an example of offers from a unit that has a positive markup and a price-based offer with a lower economic minimum MW than the cost-based offer. Keeping the startup cost, Minimum Run Time and no load cost constant between the price-based offer and cost-based offer, the dispatch cost for this unit is lower on the price-based offer than on the cost-based offer. However, the price-based offer includes a positive markup and could result in setting the market price at a noncompetitive level even after the resource owner fails the TPS test.

Figure 3-30 Offers with a positive markup but different economic minimum MW



In case of dual fuel units, if the price-based offer uses a cheaper fuel and the cost-based offer uses a more expensive fuel, the price-based offer will appear to be lower cost even when it includes a markup. Figure 3-31 shows an example of offers by a dual fuel unit, where the active cost-based offer uses a more expensive fuel and the price-based offer uses a cheaper fuel and includes a markup.

Figure 3-31 Dual fuel unit offers



These issues can be solved by simple rule changes.[61] The MMU recommends that markup of price based offers over cost-based offers be constant across the offer curve, that there be at least one cost-based offer using the same fuel as the available price-based offer, and that operating parameters on parameter limited schedules (PLS) be at least as flexible as price-based non-PLS offers.

Levels of offer capping have historically been low in PJM, as shown in Table 3-27. But offer capping remains a critical element of PJM market rules because it is designed to prevent the exercise of local market power. While overall offer capping levels have been low, there are a significant number of units with persistent structural local market power that would have a significant impact on prices in the absence of local market power mitigation. Until November 1, 2017, only uncommitted resources, started to relieve the transmission constraint, were subject to offer capping. Beginning November 1, 2017, under certain circumstances, online resources that are committed beyond their original commitment (day-ahead or real-time) can be offer capped if the owner fails the TPS test, and the latest available cost-based offer is determined to be lower than the price-based offer.[62] Units running in real time as part of their original commitment on the price-based offer on economics, and that can provide incremental relief to a constraint, cannot be switched to their cost-based offer.

61 The MMU proposed these offer rule changes as part of a broader reform to address generator offer flexibility and associated impact on market power mitigation rules in the Generator Offer Flexibility Senior Task Force (GOFSTF) and subsequently in the MMU's protest in the hourly offers proceeding in Docket No. ER16-372-000, filed December 14, 2015.

62 See OATT Attachment K Appendix § 6.4.1.

The offer capping percentages shown in Table 3-27 include units that are committed to provide constraint relief whose owners failed the TPS test in the energy market excluding units that were committed for reliability reasons, providing black start and providing reactive support. Offer capped unit run hours and offer capped generation (in MWh) are shown as a percentage of the total run hours and the total generation (MWh) from all the units in the PJM energy market.[63] Beginning November 1, 2017, with the introduction of hourly offers, certain online units, whose owners fail the TPS test in the real-time energy market for providing constraint relief, can be offer capped and dispatched on their cost-based offer subsequent to a real-time hourly offer update. This is reflected in the higher offer capping percentages in the real-time energy market in 2018 compared to 2017.

Table 3-27 Offer capping statistics – energy only: 2014 to 2018

	Real-Time		Day-Ahead	
Year	Unit Hours Capped	MWh Capped	Unit Hours Capped	MWh Capped
2014	0.5%	0.2%	0.2%	0.1%
2015	0.4%	0.2%	0.2%	0.2%
2016	0.4%	0.2%	0.0%	0.0%
2017	0.3%	0.2%	0.0%	0.0%
2018	0.9%	0.5%	0.1%	0.1%

Table 3-28 shows the offer capping percentages including units committed to provide constraint relief and units committed for reliability reasons, including units committed to provide black start service and reactive support. As of April 2015, the Automatic Load Rejection (ALR) units that were committed for black start previously no longer provide black start service, and are not included in the offer capping statistics for black start. PJM also created closed loop interfaces to, in some cases, model reactive constraints. The result was higher LMPs in the closed loops, which increased economic dispatch, which contributed to the reduction in units offer capped for reactive support. In instances where units are now committed for the modeled closed loop interface constraints, they are considered offer capped for providing constraint relief. They are included in the offer capping percentages in Table 3-27.

Table 3-28 Offer capping statistics for energy and reliability: 2014 to 2018

	Real-Time		Day-Ahead	
Year	Unit Hours Capped	MWh Capped	Unit Hours Capped	MWh Capped
2014	0.9%	0.5%	0.6%	0.4%
2015	0.7%	0.8%	0.6%	0.7%
2016	0.4%	0.3%	0.1%	0.1%
2017	0.4%	0.4%	0.1%	0.2%
2018	1.0%	0.8%	0.2%	0.3%

Table 3-29 shows the offer capping percentages for units committed for reliability reasons, including units committed to provide black start service and reactive support. The data in Table 3-29 is the difference between the offer cap percentages shown in Table 3-28 and Table 3-27.

Table 3-29 Offer capping statistics for reliability: 2014 to 2018

	Real-Time		Day-Ahead	
Year	Unit Hours Capped	MWh Capped	Unit Hours Capped	MWh Capped
2014	0.3%	0.3%	0.4%	0.3%
2015	0.3%	0.5%	0.4%	0.5%
2016	0.1%	0.1%	0.1%	0.1%
2017	0.1%	0.2%	0.1%	0.2%
2018	0.1%	0.3%	0.1%	0.2%

Table 3-30 presents data on the frequency with which units were offer capped in 2017 and 2018 as a result of failing the TPS test to provide energy for constraint relief in the Real-Time Energy Market and for reliability reasons. Table 3-30 shows that two units were offer capped for 90 percent or more of their run hours in 2018 compared to four units in 2017.

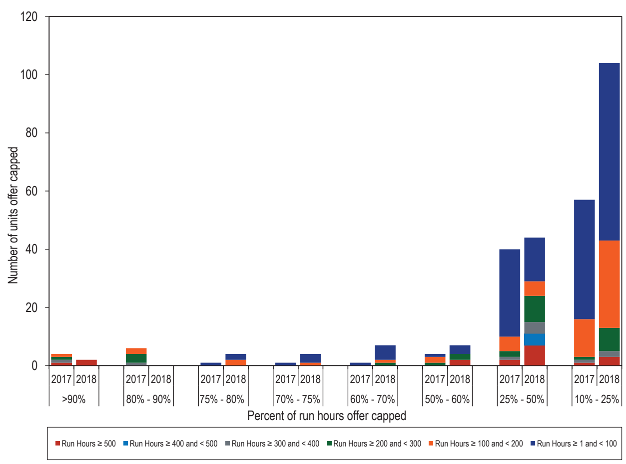
63 In the previous versions of this report, these tables presented the offer cap percentages based on total bid unit hours and total load MWh. Beginning with this report, the statistics have been updated with percentages based on run hours and total generation MWh from units modeled in the energy market.

Table 3-30 Real-time offer capped unit statistics: 2017 and 2018

		Offer-Capped Hours					
Run Hours Offer-Capped, Percent Greater Than Or Equal To:	Year	Hours ≥ 500	Hours ≥ 400 and < 500	Hours ≥ 300 and < 400	Hours ≥ 200 and < 300	Hours ≥ 100 and < 200	Hours ≥ 1 and < 100
	2017	1	0	1	1	1	0
90%	2018	2	0	0	0	0	0
	2017	0	0	1	3	2	0
80% and < 90%	2018	0	0	0	0	0	0
	2017	0	0	0	0	0	1
75% and < 80%	2018	0	0	0	0	2	2
	2017	0	0	0	0	0	1
70% and < 75%	2018	0	0	0	0	1	3
	2017	0	0	0	0	0	1
60% and < 70%	2018	0	0	0	1	1	5
	2017	0	0	0	1	2	1
50% and < 60%	2018	2	0	0	2	0	3
	2017	2	0	1	2	5	30
25% and < 50%	2018	7	4	4	9	5	15
	2017	1	0	1	1	13	41
10% and < 25%	2018	3	0	2	8	30	61

Figure 3-32 shows the frequency with which units were offer capped in 2017 and 2018 for failing the TPS test to provide energy for constraint relief in the Real-Time Energy Market and for reliability reasons.

Figure 3-32 Real-time offer capped unit statistics: 2017 and 2018



Parameter Limited Schedules

Cost-Based Offers

All capacity resources in PJM are required to submit at least one cost-based offer. During the 2016/2017 and 2017/2018 delivery years, all cost-based offers, submitted by resources that are not capacity performance resources, are parameter limited in accordance with the Parameter Limited Schedule (PLS) matrix or with the level of an approved exception.[64] During the 2016/2017 and 2017/2018 delivery years, all cost-based offers, submitted by capacity performance resources, are parameter limited in accordance with predetermined unit specific parameter limits. During the 2016/2017 and 2017/2018 delivery years, there was no base capacity procured.

For the 2018/2019 and 2019/2020 delivery years, PJM procured two types of capacity resources, capacity performance resources and base capacity resources. Beginning June 1, 2018, there will no longer be any RPM resources committed as the legacy annual capacity product that existed prior to the 2018/2019 Delivery Year. All cost-based offers, submitted by capacity performance resources and base capacity resources, are parameter limited in accordance with predetermined unit specific parameter limits.

Price-Based Offers

All capacity resources that choose to offer price-based offers are required to make available at least one price-based parameter limited offer (referred to as price-based PLS). For resources that are not capacity performance resources or not base capacity resources, the price-based parameter limited schedule is to be used by PJM for committing generation resources when a maximum emergency generation alert is declared. For capacity performance resources, the price-based parameter limited schedule is to be used by PJM for committing generation resources when hot weather alerts and cold weather alerts are declared. For base capacity resources (during the 2018/2019 and 2019/2020 delivery years only), the price-based parameter limited schedule is to be used by PJM for committing generation resources when hot weather alerts are declared.

Currently, there are no rules in the PJM tariff or manuals that limit the markup attributes of price-based PLS offers. The intent of the price-based PLS offer is to prevent the exercise of market power during high demand conditions

64 See PJM Operating Agreement Schedule 1 § 6.6.

by preventing units from offering inflexible operating parameters in order to extract higher market revenues or higher uplift payments. However, a generator can include a higher markup in the price-based PLS offer than in the price-based non-PLS schedule. The result is that the offer is higher and market prices are higher as a result of the exercise of market power using the PLS offer. This defeats the purpose of requiring price-based PLS offers.

The 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 non-PLS price-based offer, and that the price-MW pairs in the price-based PLS offer be exactly equal to the price-based non-PLS offer.

Parameter Limits

For generation capacity resources committed prior to the implementation of the capacity performance rules, the parameters that were subject to limits on their parameter limited schedules were Minimum Run Time, Minimum Down Time, Maximum Daily Starts, Maximum Weekly Starts, and Turn Down Ratio. The limits for these parameters were based on the parameter limited schedule matrix in the PJM operating agreement.[65] Startup times and notification times were not subject to limits. Market sellers could request exceptions to the limits in the matrix on a temporary basis, for up to 30 days, for physical issues that occur at the units at any time during the delivery year. Market sellers could also request longer term exceptions, called period exceptions, supported by technical documentation and historical operating data, submitted in advance of a delivery year, which were reviewed by PJM and the IMM and approved by PJM. In the PJM energy market, market sellers were required to submit operating parameters in their parameter limited schedules that were at least as flexible as the limits specified in the parameter limited schedule matrix, or an approved exception.

Beginning in the 2016/2017 Delivery Year, resources that had capacity performance (CP) commitments were required to submit, in their parameter limited schedules (cost-based offers and price-based PLS offers), unit specific parameters that reflect the physical capability of the technology type of the resource. For the 2018/2019 and 2019/2020 delivery years, resources that have base capacity commitments are also required to submit, in their parameter limited schedules, unit specific parameters that reflect the physical capability of the technology type of the resource. Startup and notification times are limited for capacity performance resources beginning June 1, 2016, and base capacity resources beginning June 1, 2018, in accordance with predetermined unit specific parameter limits. The unit specific parameter limits for capacity performance and base capacity resources are based on default minimum operating parameter limits posted by PJM by technology type, and any adjustments based on a unit specific review process. These default parameters were based on analysis by the MMU.

Beginning June 1, 2018, all RPM procured capacity resources were either capacity performance or base capacity resources. Entities that elected the fixed resource requirement (FRR) option were allowed to procure the legacy annual capacity product for the 2018/2019 Delivery Year. Beginning June 1, 2019, all capacity resources, including resources in FRR capacity plans, will be either capacity performance or base capacity resources. The PJM tariff specifies that all generation capacity resources, regardless of the current commitment status, are subject to parameter limits on their cost-based offers. However, the tariff currently does not make it clear what parameter limit values are applicable for resources without a capacity commitment. The MMU recommends that PJM update the tariff to clarify that all generation resources are subject to unit specific parameter limits on their cost-based offers using the same standard and process as capacity performance and base capacity resources.

Unit Specific Adjustment Process

Market participants can request an adjustment to the default values of parameter limits for capacity performance and base capacity resources, by submitting supporting documentation, which is reviewed by PJM and the MMU. The default minimum operating parameter limits or approved adjusted values are used by capacity performance resources and base capacity resources for their parameter limited schedules.

65 See PJM Operating Agreement Schedule 1 § 6.6 (c).

PJM has the authority to approve adjusted parameters with input from the MMU. PJM has inappropriately applied different review standards to coal units than to CTs and CCs despite the objections of the MMU. PJM has approved parameter limits for steam units based on historical performance and existing equipment while holding CTs and CCs to higher standards based on OEM documentation and up to date equipment configuration.

The PJM process for the review of unit specific parameter limit adjustments is generally described in Manual 11: Energy and Ancillary Services Market Operations. The standards used by PJM to review the requests are currently not described in the tariff or PJM manuals. The MMU recommends that PJM clearly define the business rules that apply to the unit specific parameter adjustment process, including PJM's implementation of the tariff rules in the PJM manuals to ensure market sellers know the requirements for their resources.

Only certain technology types are subject to limits on operating parameters in their parameter limited schedules.[66] Solar units, wind units, run of river hydro units, and nuclear units are currently not subject to parameter limits. The MMU analyzed, for the units that are subject to parameter limits, the proportion of units that use the default limits published by PJM and the proportion of units that have been provided unit specific adjustments for some of the parameters. Table 3-31 shows, for the delivery year beginning June 1, 2018, the number of units that submitted and were approved unit specific parameter limit adjustments, and the number of units that used the default parameter limits published by PJM.

Table 3-31 Adjusted unit specific parameter limit statistics: June through December 2018

Technology Classification	Units Using Default Parameter Limits	Units with One or More Adjusted Parameter Limits
Aero CT	136	32
Frame CT	184	104
Combined Cycle	75	36
Reciprocating Internal Combustion Engines	70	3
Solid Fuel NUG	41	4
Oil and Gas Steam	18	16
Subcritical Coal Steam	24	70
Supercritical Coal Steam	5	43
Pumped Storage	10	0

66 For the default parameter limits by technology type, see PJM. "Unit-Specific Minimum Operating Parameters for Capacity Performance and Base Capacity Resources," which can be accessed at <https://www.pjm.com/~/media/committees-groups/committees/elc/postings/20150612-june-2015-capacity-performance-parameter-limitations-informational-posting.ashx>.

Real Time Values

The MMU previously recommended that PJM market rules recognize the difference between operational parameters that indicate to PJM dispatchers what a unit is capable of during the operating day and the parameters that result in uplift payments. The parameters provided to PJM dispatchers each day should reflect what units are physically capable of so that dispatchers can operate the system. However, the parameters which determine the amount of uplift payments to those generators should reflect the flexibility goals of the capacity performance construct and the assignment of performance risk to generation owners. PJM implemented the real time value variable in Markets Gateway to address this.

PJM market rules allow generators to communicate a resource's current operational capabilities to PJM when a resource cannot operate according to the unit specific parameters. These values are called real time values (RTVs). The real-time values submittal process is not specified in the PJM Operating Agreement. The process is defined in PJM Manual 11. Unlike parameter exceptions, the use of real-time values makes a unit ineligible for make whole payments, unless the Market Seller can justify such operation based on an actual constraint.[67]

In practice, real-time values are generally used to communicate lower Turn Down Ratios which result from reduced Economic Max MW due to a derate (partial outage) on a unit, or from a requirement to operate at a defined output for equipment tests, environmental tests, or inspections. The RTV functionality allows units to communicate accurate short term operational parameters to PJM without requiring PJM customers to pay additional uplift charges, if the unit operates out of the money for routine tests and inspections. However, using real-time values to extend the time to start parameters (startup times and notification times) is inconsistent with the goal of real-time values. The protection offered by making units ineligible for uplift is only effective if the unit is committed and operated out of the money because of the RTVs. In the case of the notification time parameter or start time parameter, a longer real-time value decreases the likelihood of the unit being committed at all and may prohibit unit

67 See PJM Operating Agreement Schedule 1 Section 3.2.3 (e).

commitment in real time, making this a mechanism for withholding.

The use of real-time values to extend startup times and notification times allows generators to circumvent the parameter limited schedule rules, to avoid commitment by PJM. Using RTVs to remove a unit from the real-time look-ahead dispatch window, and avoid commitment is withholding. These concerns are exacerbated if these units can otherwise provide relief to transmission constraints, and can provide flexibility to meet peak demand conditions. Currently, a resource that is staffed or has remote start capability and offers according to its physical capability, and a resource that makes the economic choice not to staff or invest in remote start and offers to decrease the likelihood of commitment, are treated as identical in the capacity market. If a market seller makes an economic decision to not staff the unit or have remote start capability, and uses real-time values to communicate the longer time to start to PJM, there is currently no consequence to the market seller.

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 justifications.

Generator Flexibility Incentives under Capacity Performance

In its order on capacity performance, the Commission determined that capacity performance resources should be able to reflect actual constraints based on not just the resource physical constraints, but also other constraints, such as contractual limits that are not based on the physical characteristics of the generator.[68] The Commission directed that capacity performance resources with parameters based on nonphysical constraints should receive uplift payments.[69] The Commission directed PJM to submit tariff language to establish a process through which capacity performance resources that operate outside the defined unit-specific parameter limits can justify such operation and therefore remain eligible for make whole payments.[70]

68 151 FERC ¶ 61,208 at P 437 (2015) (June 9th Order).
69 *Id* at P 439.
70 *Id* at P 440.

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

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

The approach to parameters defined in the June 9th Order will increase energy market uplift payments substantially. Uplift costs are unpredictable, opaque and unhedgeable. While some uplift is necessary and efficient in an LMP market, this uplift is not. Electric customers are not in a position to determine the terms of the contracts that resources enter into. Customers rely on the market rules to create incentives that protect them by assigning operational risk to generators, who are in the best position to efficiently manage those risks.

The MMU recommends that capacity performance resources and base capacity resources (during the June through September period) be held to the OEM operating parameters of the capacity market reference resource used for the Cost of New Entry (CONE) calculation for performance assessment and energy uplift payments and that this standard be applied to all technologies on a uniform basis. This solution creates the incentives for flexibility and preserves, to the extent possible, the incentives to follow PJM's dispatch instructions during high demand conditions. The proposed operating parameters should be based on the physical capability of the Reference Resource used in the Cost of New Entry, currently two GE Frame 7FA turbines with dual fuel capability. All resources that are less flexible than the reference resource are expected to be scheduled and running during high demand conditions anyway, while the flexible CTs that are used as peaking plants would still have the incentive to follow LMP and dispatch instructions. CCs would also have the capability to be as flexible as the reference resource. These units will be exempt from nonperformance charges and made whole as long as they perform in accordance with their parameters. This ensures that all the peaking units that are needed by PJM for flexible operation do not self schedule at their maximum output, and follow PJM dispatch instructions during high demand conditions. If any of the less flexible resources need to be dispatched down by PJM for reliability reasons, they would be exempt from nonperformance charges.

Such an approach is consistent with the Commission's no excuses policy for nonperformance because the flexibility target is set based on the optimal OEM-defined capability for the marginal resource that is expected to meet peak demand, which is consistent with the level of performance that customers are paying for in the capacity market. Any resource that is less flexible is not excused for nonperformance and any resource that meets the flexibility target is performing according to the commitments made in the capacity market.

The June 9th Order pointed out that the way to ensure that a resource's parameters are exposed to market consequences is to not allow any parameter limitations as an excuse for nonperformance. The same logic should apply to energy market uplift rules. A resource's parameters should be exposed to market consequences and the resource should not be made whole if it is operating less flexibly than the reference resource. Paying energy market uplift on the basis of parameters consistent with the flexibility goals of the capacity performance construct would ensure that performance incentives are consistent across the capacity and energy markets and ensure that performance risk is appropriately assigned to generation owners.

Parameter Impacts of Gas Pipeline Conditions

During the extreme cold weather conditions in 2018, 2017, 2016, 2015, and 2014, a number of gas fired generators requested temporary exceptions to parameter limits for their parameter limited schedules due to restrictions imposed by natural gas pipelines. The parameters that were affected include notification time, minimum run time (MRT) and turn down ratio (TDR, the ratio of economic maximum MW to economic minimum MW). When pipelines issue critical notices and enforce ratable take requirements, generators may, depending on the nature of the transportation service purchased, be forced to nominate an equal amount of gas for each hour in a 24 hour period, with penalties for deviating from the nominated quantity. This led to requests for 24 hour minimum run times and turn down ratios close to 1.0, to avoid deviations from the hourly nominated quantity.

Key parameters like startup and notification time were not included in the PLS matrix in 2017 and prior periods, even though other parameters were subject to parameter limits. Some resource owners notified PJM that they needed extended notification times based on the claimed necessity for generation owners to nominate gas prior to gas nomination cycle deadlines.

Markup Index

Markup is a summary measure of participant offer behavior or conduct for individual units. When a seller responds competitively to a market price, markup is zero. When a seller exercises market power in its pricing, markup is positive. The degree of markup increases with the degree of market power. The markup index for each marginal unit is calculated as (Price – Cost)/Price.[71] The markup index is normalized and can vary from -1.00 when the offer price is less than short run marginal cost, to 1.00 when the offer price is higher than short run

71 In order to normalize the index results (i.e., bound the results between +1.00 and -1.00) for comparison across both low and high cost units, the index is calculated as (Price – Cost)/Price when price is greater than cost, and (Price – Cost)/Cost when price is less than cost.

marginal cost. The markup index does not measure the impact of unit markup on total LMP. The dollar markup for a unit is the difference between price and cost.

Real-Time Markup Index

Table 3-32 shows the average markup index of marginal units in the Real-Time Energy Market, by offer price category using unadjusted cost-based offers. Table 3-33 shows the average markup index of marginal units in the Real-Time Energy Market, by offer price category using adjusted cost-based offers. The unadjusted markup is the difference between the price-based offer and the cost-based offer including the 10 percent adder in the cost-based offer. The adjusted markup is the difference between the price-based offer and the cost-based offer excluding the 10 percent adder from the cost-based offer. The adjusted markup is calculated for coal, gas and oil units because these units have consistently had price-based offers less than cost-based offers.[72] The markup is negative if the cost-based offer of the marginal unit exceeds its price-based offer at its operating point.

All generating units are allowed to add an additional 10 percent to their cost-based offer. The 10 percent adder was included prior to the implementation of PJM markets in 1999, based on the uncertainty of calculating the hourly operating costs of CTs under changing ambient conditions. The owners of coal units, facing competition, typically exclude the additional 10 percent from their actual offers. The owners of many gas fired and oil fired units have also begun to exclude the 10 percent adder. The introduction of hourly offers and intraday offer updates in November 2017 allows gas and oil generators to directly incorporate the impact of ambient temperature changes in fuel consumption in offers.

The unadjusted markup is calculated as the difference between the price-based offer and the cost-based offer including the additional 10 percent in the cost-based offer for coal, gas and oil fired units. The adjusted markup is calculated as the difference between the price-based offer and the cost-based offer excluding the additional 10 percent from the cost-based offers of coal, gas and oil fired units. Even the adjusted markup overestimates the negative markup because units facing increased competitive pressure have excluded both the 10 percent and components of operating and maintenance costs that are not short run marginal costs. While the 10 percent adder is permitted under the definition of cost-based offers in the PJM Market Rules and some have interpreted the rules to permit maintenance costs that are not short run marginal costs, neither are part of a competitive offer because they are not actually short run marginal costs, and actual market behavior reflects that fact.[73]

In 2018, 88.1 percent of marginal units had offer prices less than $50 per MWh. The average dollar markups of units with offer prices less than $25 was negative (-$0.44 per MWh) when using unadjusted cost-based offers. The average dollar markups of units with offer prices between $25 and $50 was positive ($1.91 per MWh) when using unadjusted cost-based offers. Negative markup means the unit is offering to run at a price less than its cost-based offer, revealing a short run marginal cost that is less than the maximum allowable cost-based offer under the PJM Market Rules.

Some marginal units did have substantial markups. Among the units that were marginal in 2018, 0.1 percent had offer prices above $400 per MWh. Among the units that were marginal in 2017, less than 0.1 percent had offer prices greater than $400 per MWh. Using the unadjusted cost-based offers, the highest markup for any marginal unit in 2018 was more than $500, while the highest markup in 2017 was more than $700.

Table 3-32 Average, real-time marginal unit markup index (By offer price category unadjusted): 2017 and 2018

	2017			2018		
Offer Price Category	Average Markup Index	Average Dollar Markup	Frequency	Average Markup Index	Average Dollar Markup	Frequency
< $25	0.14	($0.00)	63.4%	0.03	($0.44)	49.2%
$25 to $50	0.06	$1.57	28.1%	0.06	$1.91	38.9%
$50 to $75	0.37	$20.20	1.9%	0.27	$14.86	3.7%
$75 to $100	0.29	$23.85	0.7%	0.31	$25.39	1.1%
$100 to $125	0.23	$25.00	0.3%	0.34	$37.74	0.6%
$125 to $150	0.19	$24.46	0.4%	0.13	$18.33	0.9%
$150 to $400	0.01	$2.07	5.2%	0.05	$9.06	5.5%
>= $400	0.69	$426.87	0.0%	0.27	$130.38	0.1%

72 The MMU will calculate adjusted markup for gas units also in future reports because gas units also more consistently have price-based offers less than cost-based offers.

73 See PJM. "Manual 15: Cost Development Guidelines," Rev. 30 (Dec. 4, 2018).

Table 3-33 Average, real-time marginal unit markup index (By offer price category adjusted): 2017 and 2018

	2017			2018		
Offer Price Category	Average Markup Index	Average Dollar Markup	Frequency	Average Markup Index	Average Dollar Markup	Frequency
< $25	0.22	$1.56	63.4%	0.11	$1.25	49.2%
$25 to $50	0.14	$4.23	28.1%	0.14	$4.62	38.9%
$50 to $75	0.42	$23.48	1.9%	0.33	$18.69	3.7%
$75 to $100	0.36	$29.63	0.7%	0.37	$30.65	1.1%
$100 to $125	0.30	$32.83	0.3%	0.41	$44.43	0.6%
$125 to $150	0.26	$34.55	0.4%	0.22	$28.96	0.9%
$150 to $400	0.11	$19.66	5.2%	0.14	$27.01	5.5%
>= $400	0.72	$438.38	0.0%	0.33	$159.95	0.1%

Table 3-34 shows the percentage of marginal units that had markups, calculated using unadjusted cost-based offers, below, above and equal to zero for coal, gas and oil fuel types.[74] Table 3-35 shows the percentage of marginal units that had markups, calculated using adjusted cost-based offers, below, above and equal to zero for coal, gas and oil fuel types. In 2018, using unadjusted cost-based offers for coal units, 48.26 percent of marginal coal units had negative markups. In 2018, using adjusted cost-based offers for coal units, 18.27 percent of marginal coal units had negative markups.

Table 3-34 Percent of marginal units with markup below, above and equal to zero (By fuel type unadjusted): 2017 and 2018

	2017			2018		
Type/Fuel	Negative	Zero	Positive	Negative	Zero	Positive
Coal	45.45%	22.22%	32.32%	48.26%	19.91%	31.83%
Gas	36.06%	13.01%	50.93%	42.24%	12.52%	45.23%
Oil	25.07%	73.92%	1.01%	6.18%	89.11%	4.71%

Table 3-35 Percent of marginal units with markup below, above and equal to zero (By fuel type adjusted): 2017 and 2018

	2017			2018		
Type/Fuel	Negative	Zero	Positive	Negative	Zero	Positive
Coal	24.05%	4.84%	71.10%	18.27%	0.11%	81.62%
Gas	10.18%	4.90%	84.92%	9.99%	0.04%	89.96%
Oil	0.34%	0.00%	99.66%	0.53%	0.00%	99.47%

Figure 3-33 shows the frequency distribution of hourly markups for all gas units offered in 2017 and 2018 using unadjusted cost-based offers. The highest markup within the economic operating range of the unit's offer curve was used for creating the frequency distributions.[75] Of the gas units offered in the PJM market in 2018, nearly 27.4 percent of gas unit-hours had a maximum markup that was negative. More than 10.7 percent of gas fired unit-hours had a maximum markup above $100 per MWh.

Figure 3-33 Frequency distribution of highest markup of gas units offered using unadjusted cost offers: 2017 and 2018

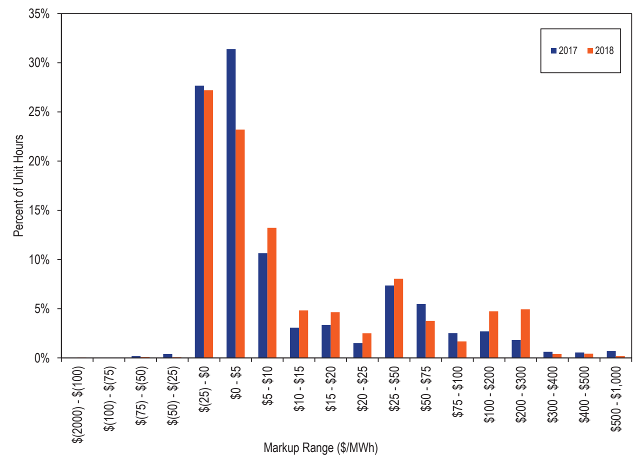
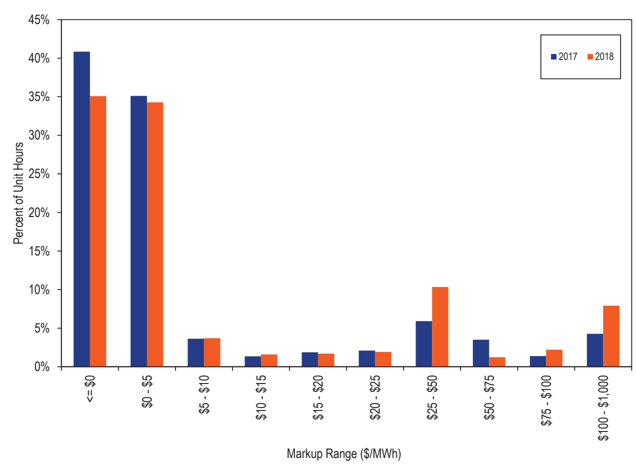


Figure 3-34 shows the frequency distribution of hourly markups for all coal units offered in 2017 and 2018 using unadjusted cost-based offers. Of the coal units offered in the PJM market in 2018, nearly 35 percent of coal unit-hours had a maximum markup that was negative or equal to zero.

Figure 3-34 Frequency distribution of highest markup of coal units offered using unadjusted cost offers: 2017 and 2018

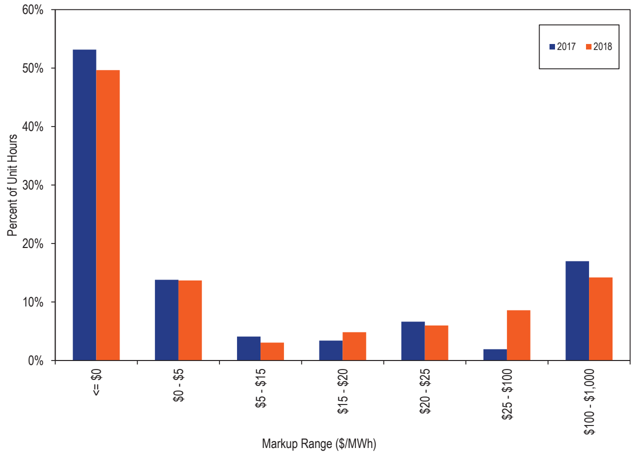


74 Other fuel types were excluded based on data confidentiality rules.

75 The categories in the frequency distribution were chosen so as to maintain data confidentiality.

Figure 3-35 shows the frequency distribution of hourly markups for all offered oil units in 2017 and 2018 using unadjusted cost-based offers. Of the oil units offered in the PJM market in 2018, nearly 49 percent of oil unit-hours had a maximum markup that was negative or equal to zero. More than 14 percent of oil fired unit-hours had a maximum markup above $100 per MWh.

Figure 3-35 Frequency distribution of highest markup of oil units offered using unadjusted cost offers: 2017 and 2018

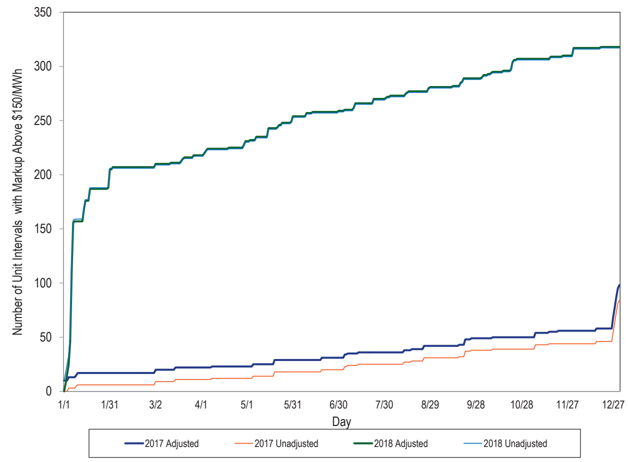


The markup frequency distributions show that a significant proportion of units make price-based offers less than the cost-based offers permitted under the PJM market rules. This behavior means that competitive price-based offers reveal actual unit marginal costs and that PJM market rules permit the inclusion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

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

Figure 3-36 shows the number of marginal unit intervals in 2018 and 2017 with markup above $150 per MWh. The number of intervals with markups above $150 per MWh increased during the first eight days of January 2018, when the PJM region experienced low temperatures.

Figure 3-36 Cumulative number of unit intervals with markups above $150 per MWh: 2017 and 2018



Day-Ahead Markup Index

Table 3-36 shows the average markup index of marginal generating units in the Day-Ahead Energy Market, by offer price category using unadjusted cost-based offers. The majority of marginal units are virtual transactions, which do not have markup. In 2018, 95.5 percent of marginal generating units had offer prices less than $50 per MWh. The average dollar markups of units with offer prices less than $25 was positive ($0.27 per MWh) when using unadjusted cost-based offers. The average dollar markups of units with offer prices between $25 and $50 was positive ($3.21 per MWh) when using unadjusted cost-based offers.

Some marginal units did have substantial markups. Among the units that were marginal in the day-ahead market in 2017 and 2018, none had offer prices above $400 per MWh. Using the unadjusted cost-based offers, the highest markup for any marginal unit in the day-ahead market in 2018 was about $200 per MWh while the highest markup in 2017 was about $85 per MWh.

Table 3-36 Average day-ahead marginal unit markup index (By offer price category, unadjusted): 2017 and 2018

	2017			2018		
Offer Price Category	Average Markup Index	Average Dollar Markup	Frequency	Average Markup Index	Average Dollar Markup	Frequency
< $25	0.14	$0.26	60.1%	0.05	$0.27	50.4%
$25 to $50	0.10	$2.87	32.7%	0.10	$3.21	45.1%
$50 to $75	0.32	$17.41	1.0%	0.24	$13.39	2.2%
$75 to $100	0.04	$0.15	0.4%	0.31	$24.82	0.6%
$100 to $125	0.05	$4.48	0.1%	0.04	$3.60	0.3%
$125 to $150	(0.05)	($8.80)	0.1%	0.07	$8.99	0.4%
>= $150	(0.00)	($0.79)	5.6%	0.07	$13.30	0.9%

Table 3-37 shows the average markup index of marginal generating units in the Day-Ahead Energy Market, by offer price category using adjusted cost-based offers. In 2018, 0.6 percent of marginal generating units had offers between $75 and $100 per MWh and the average dollar markup and the average markup index were both positive. The average markup index decreased from 0.22 in 2017, to 0.13 in 2018 in the offer price category less than $25.

Table 3-37 Average day-ahead marginal unit markup index (By offer price category, adjusted): 2017 and 2018

	2017			2018		
Offer Price Category	Average Markup Index	Average Dollar Markup	Frequency	Average Markup Index	Average Dollar Markup	Frequency
< $25	0.22	$1.93	60.1%	0.13	$1.98	50.4%
$25 to $50	0.17	$5.35	32.7%	0.17	$5.80	45.1%
$50 to $75	0.37	$20.81	1.0%	0.31	$17.21	2.2%
$75 to $100	0.12	$8.18	0.4%	0.37	$29.91	0.6%
$100 to $125	0.13	$13.79	0.1%	0.12	$13.39	0.3%
$125 to $150	0.04	$4.28	0.1%	0.15	$20.16	0.4%
>= $150	0.09	$16.43	5.6%	0.15	$30.43	0.9%

Energy Market Cost-Based Offers

The application of market power mitigation rules in the Day-Ahead Energy Market and the Real-Time Energy Market helps ensure competitive market outcomes even in the presence of structural market power. But the efficacy of market power mitigation rules depends on the definition of a competitive offer. A competitive offer is equal to short run marginal costs. The enforcement of market power mitigation rules is undermined if the definition of a competitive offer is not correct. The significance of competition metrics like markup is also undermined if the definition of a competitive offer is not correct. The definition of a competitive offer, as interpreted by PJM, is not currently correct. Some unit owners include costs that are not short run marginal costs in offers, including maintenance costs. This issue can be resolved by simple changes to the PJM market rules to incorporate a clear and accurate definition of short run marginal costs.

Short Run Marginal Costs

There are three types of costs identified under PJM rules:

- Short run marginal costs. Cost of inputs consumed or converted to produce energy, and the costs associated with byproducts that result from consuming or converting materials to produce energy, net of any revenues from the sale of those byproducts. The categories of short run marginal costs are:
  - Fuel costs: Includes commodity costs, delivery costs (such as variable transportation costs), fuel supplier fees and taxes;
  - Emission allowance costs: Includes costs of emission allowances and any variable regulatory fees;
  - Operating costs: Includes water purchases, water or waste water treatment control reagents, emission control reagents, equipment lubricants, electricity byproducts disposal;
  - Energy market opportunity costs;[76]
- Avoidable costs. Annual costs that would be avoided if energy were not produced over an annual period, e.g. overhaul and maintenance costs;
- Fixed costs. Costs associated with an investment in a facility including the return on and of capital.

Marginal costs are the only costs relevant to the energy market. Specifically, the competitive energy offer level is the short run marginal cost of production.

The MMU recommends that PJM require that the level of incremental costs includable in cost-based offers not exceed the unit's short run marginal cost.

Fuel Cost Policies

Fuel cost policies (FCP) document the process by which market sellers calculate the fuel cost component of their cost-based offers. Short run marginal fuel costs include

76 See PJM Operating Agreement Schedule 2 (a)

commodity costs, transportation costs, fees, and taxes for the purchase of fuel.

Fuel cost policies are submitted under four scenarios:[77]

1. During the annual review process: The annual review begins on June 15 (the deadline for Market sellers to submit fuel cost policies per the annual review) and ends on November 1 (the deadline for PJM to approve or reject policies submitted as part of the annual review).
2. Outside the annual review process: Market sellers can submit new fuel cost policies. PJM and the MMU have 30 business days to review the submitted fuel cost policy.
3. New units: Owners of new units are required to submit a provisional fuel cost policy 45 days prior to the first day the market seller expects to make a cost-based offer, or a later date approved by PJM. Also, new units are required to submit a final fuel cost policy 90 days after the unit has been declared commercially available.
4. Unit transfers: Owners for existing units that are being transferred are required to submit a fuel cost policy 45 days prior to the unit transfer or a later date approved by PJM.

Fuel Cost Policy Review

Table 3-38 shows the summary of the 2018 Annual Fuel Cost Policy Review. In this review, 1,127 units (87 percent) had an FCP passed by the MMU and 174 units (13 percent) had an FCP failed by the MMU. The number of units with fuel cost policies failed by the MMU added up to 27,707 MW. All units had an FCP approved by PJM. The number of units with fuel cost policies passed by the MMU increased 3 percentage points from 84 percent in 2017 to 87 percent in 2018.

Table 3-38 Annual FCP Review Results: 2018

	MMU Status			
PJM Status	Pass	Submitted	Fail	Total
Approved	1,127	0	174	1,301
Rejected	0	0	0	0
Under Review	0	0	0	0
Submitted	0	0	0	0
Total	1,127	0	174	1,301

77 See PJM "Manual 15: Cost Development Guidelines," Rev. 30 (Dec. 4, 2018).

The MMU performed a detailed review of every FCP. PJM approved the FCPs that the MMU passed. PJM approved every FCP failed by the MMU.

The standards for the MMU's market power evaluation are that FCPs be algorithmic, verifiable and systematic, accurately reflecting the short run marginal cost of producing energy. In its filings with FERC, PJM agreed with the MMU that FCPs should be verifiable and systematic:[78]

- Verifiable: Must provide a fuel price that can be calculated by the MMU after the fact with the same data available to the Market Seller at the time the decision was made and documentation for that data from a public or a private source.
- Systematic: Document a standardized method or methods for calculating fuel costs including objective triggers for each method.[79]

PJM and FERC did not agree that Fuel Cost Policies should be algorithmic:[80]

- Algorithmic: Must use a set of defined, logical steps. These steps may be as simple as a single number from a contract, a simple average of broker quotes, a simple average of bilateral offers, or the weighted average index price posted on the Intercontinental Exchange trading platform ('ICE').[81]

FCPs are not verifiable and systematic if they are not algorithmic. The natural gas FCPs failed by the MMU and approved by PJM are not verifiable and systematic.

Not all FCPs approved by PJM met the standard of the PJM tariff. The tariff standards that some Fuel Cost Policies did not meet are:[82]

1. Accuracy: Reflect applicable costs accurately;
2. Procurement Practices: Provide information sufficient for the verification of the market seller's fuel procurement practices;
3. Fuel Contracts: Reflect the market seller's applicable commodity and/or transportation contracts (to the extent it holds such contracts).

78 Answer of PJM Interconnection, L.L.C. to Protests and Comments, Docket No. ER16-372-002 (October 7, 2016) ("October 7th Filing") at P 11.
79 Protest of the Independent Market Monitor for PJM, Docket No. ER16-372-002 (September 16, 2016) ("September 16th Filing") at P 8.
80 October 7th Filing at P12; 158 FERC ¶ 61,133 at P 57 (2017) ("February 3rd Order").
81 September 16th Filing at P 8.
82 See PJM Operating Agreement Schedule 2 § 2.3 (a).

The MMU failed FCPs not related to natural gas submitted by some market sellers because they do not accurately describe the short run marginal cost of fuel. Some policies include contractual terms (in $ per MWh or in $ per MMBtu) that do not reflect the actual cost of fuel. The MMU determined that the terms used in these policies do not reflect the cost of fuel based on the information provided by the Market Sellers and information gathered by the MMU for similar resources.

The MMU failed the remaining FCPs because they do not accurately reflect the cost of natural gas. The main issues identified by the MMU in the natural gas policies were:

- Unverifiable cost estimates. Some of these policies include options under which the estimate of the natural gas commodity cost would be calculated by the market seller without specifying a verifiable, quantitative method. For example, some FCPs specify that the source of the natural gas cost would be communications with traders within the market seller's organization. A fuel cost from discretionary and undocumented decision making within the market seller's organization is not verifiable. The point of FCPs is to eliminate such practices as the basis for fuel costs, as most companies have done. Verifiability requires that fuel cost estimates be transparently derived from market information and that PJM or the MMU could reproduce the same fuel cost estimates after the fact by applying the methods documented in the FCP to the same inputs. Verifiable is a key requirement of an FCP. If it is not verifiable, an FCP is meaningless and has no value. Unverifiable fuel costs permit the exercise of market power.
- Use of available market information that results in inaccurate expected costs. Some market sellers include the use of offers to sell natural gas on ICE as the sole basis for the cost of natural gas. An offer to sell is generally not an accurate indication of the expected fuel cost. The price of uncleared offers on the exchange generally exceeds the price of cleared transactions. Use of sell offers alone is equivalent to using the supply curve alone to determine the market price of a good without considering the demand curve. It is clearly incorrect.

The FCPs that failed the MMU's evaluation also fail to meet the standards defined in the PJM tariff. PJM should not have approved inaccurate Fuel Cost Policies.

The MMU recommends that PJM require that all fuel cost policies be algorithmic, verifiable, and systematic.

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 as the basis for Fuel Cost Policies but should not be required. In a large number of approved Fuel Cost Policies, the actual fuel procurement process plays no role in calculating the Market Seller's accurate estimate of the daily replacement value of their fuel.

The MMU recommends that PJM change the Fuel Cost Policy requirement to apply only to units that will be offered with nonzero cost-based offers. PJM should set to zero the cost-based offers of units without an approved Fuel Cost Policy.

Hourly Offers and Intraday Offer Updates

On November 1, 2017, PJM implemented hourly offers and intraday offer updates. Hourly offers means the ability to offer hourly differentiated offers (up to one offer per hour instead of one offer per day). Intraday offer updates means the ability to make changes to an offer after the rebid period. All participants are eligible to make hourly offers. Participants must opt in on a monthly basis to make intraday offer updates. Table 3-39 shows the daily average number of units that opted in to intraday offer updates and as a reference the daily average number of units that make positive offers. In December 2018, a daily average of 335 natural gas fired units had opted in for intraday offer updates out of a daily average of 448 natural gas fired units. This is an increase of 26.2 percent from the daily average number of natural gas fired units that opted in to intraday offer updates in December 2017.

Table 3-39 Average number of units opted in for intraday offers by month: 2017 and 2018

	2017						2018					
	Number of units opt in			Number of units with positive offers			Number of units opt in			Number of units with positive offers		
	Natural Gas	Other Fuels	Total	Natural Gas	Other Fuels	Total	Natural Gas	Other Fuels	Total	Natural Gas	Other Fuels	Total
Jan	0.0	0.0	0.0	444.2	419.7	863.9	291.0	32.0	323.0	444.0	394.7	838.7
Feb	0.0	0.0	0.0	445.2	419.0	864.2	302.0	32.0	334.0	444.0	395.7	839.7
Mar	0.0	0.0	0.0	447.5	418.4	865.9	304.0	32.0	336.0	444.5	394.6	839.0
Apr	0.0	0.0	0.0	448.4	419.9	868.3	312.6	32.0	344.6	445.9	394.0	839.9
May	0.0	0.0	0.0	449.7	417.1	866.7	327.5	32.0	359.5	444.9	393.2	838.0
Jun	0.0	0.0	0.0	451.7	417.5	869.2	330.0	32.0	362.0	443.3	369.8	813.1
Jul	0.0	0.0	0.0	449.0	410.4	859.4	330.0	34.0	364.0	443.0	367.4	810.5
Aug	0.0	0.0	0.0	449.0	401.5	850.5	330.0	36.0	366.0	445.0	363.7	808.7
Sep	0.0	0.0	0.0	448.5	401.4	849.9	330.0	36.0	366.0	445.2	360.1	805.3
Oct	0.0	0.0	0.0	450.8	399.5	850.3	330.0	36.0	366.0	446.5	360.1	806.6
Nov	243.6	29.0	272.6	442.3	396.8	839.1	334.0	37.0	371.0	447.8	360.5	808.3
Dec	265.8	29.0	294.8	444.2	395.2	839.4	335.4	37.0	372.4	448.4	360.2	808.5

Table 3-40 shows the average number of units that made hourly differentiated offers in the day-ahead market or rebid period.[83] In December 2018, an average of 269 units made hourly differentiated offers. This is an increase of 25.2 percent from the average number of units that made hourly differentiated offers in December 2017.

Table 3-40 Average number of units with hourly differentiated offers by month: 2017 and 2018

	2017			2018		
	Natural Gas	Other Fuels	Total	Natural Gas	Other Fuels	Total
Jan	0.0	0.0	0.0	207.0	12.4	219.4
Feb	0.0	0.0	0.0	214.4	10.5	224.9
Mar	0.0	0.0	0.0	215.0	11.6	226.6
Apr	0.0	0.0	0.0	231.3	11.4	242.8
May	0.0	0.0	0.0	242.6	11.8	254.4
Jun	0.0	0.0	0.0	246.6	9.0	255.6
Jul	0.0	0.0	0.0	247.0	11.3	258.3
Aug	0.0	0.0	0.0	259.6	16.6	276.2
Sep	0.0	0.0	0.0	238.2	14.9	253.1
Oct	0.0	0.0	0.0	252.6	17.9	270.5
Nov	212.8	10.7	223.5	261.9	25.6	287.6
Dec	200.7	14.4	215.1	244.7	24.6	269.4

Table 3-41 shows the average number of units that made rebid offer updates and intraday offer updates. In December 2018, an average of 121 units made intraday offer updates. This is an increase of 17.9 percent from the average number of units that made intraday offer updates in December 2017. Prior to November 2017, real-time offer updates refers to offer updates made during the rebid period.

Table 3-41 Average number of units making rebid or intraday offer updates by month: 2017 and 2018

	2017			2018		
	Average number of units that made real-time offer updates			Average number of units that made real-time offer updates		
	Natural Gas	Other Fuels	Total	Natural Gas	Other Fuels	Total
Jan	30.4	4.3	34.6	114.1	3.8	117.8
Feb	33.0	5.0	38.0	117.3	4.9	122.2
Mar	28.9	4.6	33.5	113.5	6.2	119.7
Apr	28.1	5.1	33.2	116.8	5.2	122.0
May	31.6	4.6	36.2	122.2	4.8	127.0
Jun	28.0	4.9	32.9	124.7	4.4	129.1
Jul	22.0	3.9	25.9	128.1	4.4	132.5
Aug	30.7	1.8	32.5	130.2	3.4	133.6
Sep	31.5	1.1	32.5	124.3	4.3	128.6
Oct	31.4	1.5	32.8	132.0	3.9	135.9
Nov	99.9	4.7	104.6	127.2	4.5	131.6
Dec	99.0	3.7	102.7	116.4	4.7	121.0

Cost-Based Offer Penalties

In addition to implementing the Fuel Cost Policy approval process, the February 3, 2017, FERC order created a process for penalizing generators identified by PJM or the MMU with cost-based offers that do not comply with Schedule 2 of the PJM Operating Agreement and PJM Manual 15.[84] Penalties became effective May 15, 2017.

In 2018, 193 penalty cases were identified, 147 resulted in assessed cost-based offer penalties, 22 resulted in disagreement between the MMU and PJM, and 24 remain pending PJM's determination. These cases were from 143 units owned by 35 different companies. Table 3-43 shows the penalties by the year in which participants were notified.

83 The information in this table was not correct for the *2017 State of the Market Report for PJM*, the *2018 Quarterly State of the Market Report for PJM: January through March* and the *2018 Quarterly State of the Market Report for PJM: January through June*.

84 158 FERC ¶ 61,133 (2017) ("February 3rd Order").

Table 3-42 Cost-based offer penalty cases by year notified: 2017 through 2018

Year notified	Cases	Assessed penalties	MMU and PJM Disagreement	Pending cases	Number of units impacted	Number of companies impacted
2017	57	56	1	0	55	16
2018	193	147	22	24	143	35
Total	250	203	23	24	193	42

Since 2017, 250 penalty cases have been identified, 203 resulted in assessed cost-based offer penalties, 23 resulted in disagreement between the MMU and PJM, and 24 remain pending PJM's determination. The 203 cases were from 205 units owned by 41 different companies. The total penalties were $1.6 million, charged to units that totaled 40,426 available MW. The average penalty was $1.92 per available MW.[85] Table 3-43 shows the total cost-based offer penalties since 2017 by year.

Table 3-43 Cost-based offer penalties by year: May 2017 through December 2018

Year	Number of units	Number of companies	Penalties	Average Available Capacity Charged (MW)	Average Penalty ($/MW)
2017	92	19	$556,826	16,930	$1.56
2018	113	29	$1,084,236	23,496	$2.18
Total	205	41	$1,641,063	40,426	$1.92

The incorrect cost-based offers resulted from incorrect application of Fuel Cost Policies, lack of approved Fuel Cost Policies, Fuel Cost Policy violations, miscalculation of no load costs, inclusion of prohibited maintenance costs, use of incorrect incremental heat rates, use of incorrect start cost, and use of incorrect emission costs.

Cost Development Guidelines

The Cost Development Guidelines contained in PJM Manual 15 do not clearly or accurately describe the short run marginal cost of generation. The MMU recommends that PJM Manual 15 be replaced 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.

VOM Costs

PJM Manual 15 and the PJM Operating Agreement Schedule 2 include rules related to VOM costs. These rules are unclear. PJM Manual 15 provides for the inclusion of Variable Operating and Maintenance (VOM) costs in energy market cost-based offers. PJM Manual 15 is unclear regarding the inclusion of variable operating costs. PJM Manual 15 includes provisions for incremental maintenance costs mainly based on FERC's accounting system. A competitive offer, at short run marginal costs, includes only operating costs. Effective market power mitigation requires excluding maintenance costs from cost-based offers.

PJM Manual 15 allows for the calculation of VOM costs in $ per MMBtu, $ per equivalent operating hour (EOH) and $ per start. PJM Manual 15 allows for the use of VOM costs in $ per MWh in the peaking segments of combustion turbines and combined cycles. The MMU converted all VOM costs into $ per MWh using benchmark heat rates by unit type and using the average economic maximum and average minimum run time of the units in 2018.

In 2018, PJM, for the most part, approved separate variable operations costs and separate variable maintenance costs per the request of the MMU. The variable operations costs can be compared to the MMU new entrant benchmark VOM. The MMU does not include maintenance costs in the new entrant benchmark VOM because maintenance costs are not short run marginal costs. Any maintenance cost included in cost-based offers raises cost-based offers above the competitive level.

Figure 3-37 shows the PJM approved VOM costs for combustion turbines and diesels, aggregated and converted into dollars per MWh. The variable operations costs are equal to short run marginal costs while variable maintenance costs are not. The average variable operations cost approved by PJM for combustion turbines and diesels was $0.48 per MWh (the MMU benchmark for a new entrant combustion turbine is $0.39 per MWh). The average variable maintenance cost approved by PJM for combustion turbines and diesels was $33.21 per MWh. The average is skewed by high outliers.

85 Cost-based offer penalties are assessed by hour. Therefore, a $1 per available MW penalty results in a total of $24 for a 1 MW unit if the violation is for the entire day.

Figure 3-37 PJM approved variable operations and maintenance (VOM) costs for combustion turbines and diesels: 2018

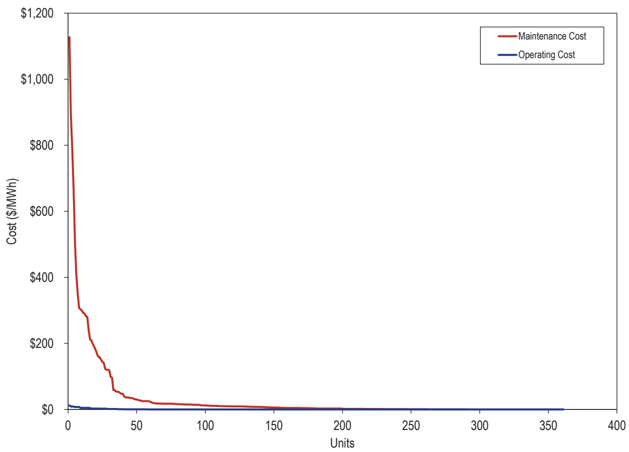


Figure 3-38 shows the PJM approved VOM costs for combined cycles, aggregated and converted into dollars per MWh. The variable operations costs are equal to short run marginal costs while variable maintenance costs are not. The average variable operations cost approved by PJM for combined cycles was $0.73 per MWh (the MMU benchmark for a new entrant combined cycle is $1.09 per MWh). The average variable maintenance cost approved by PJM for combined cycles was $3.21 per MWh. The average is skewed by high outliers.

Figure 3-38 PJM approved variable operations and maintenance (VOM) costs for combined cycle units: 2018

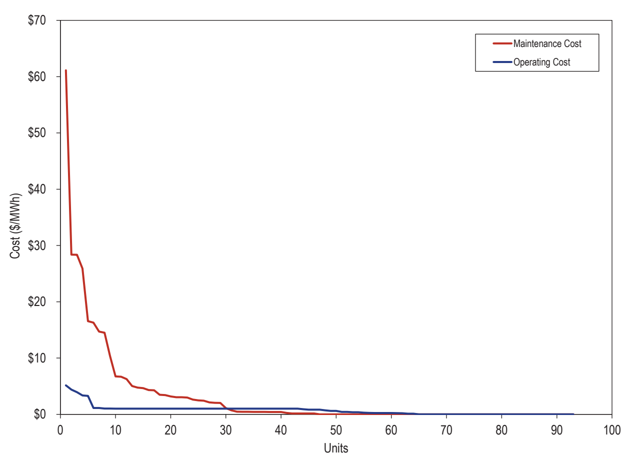
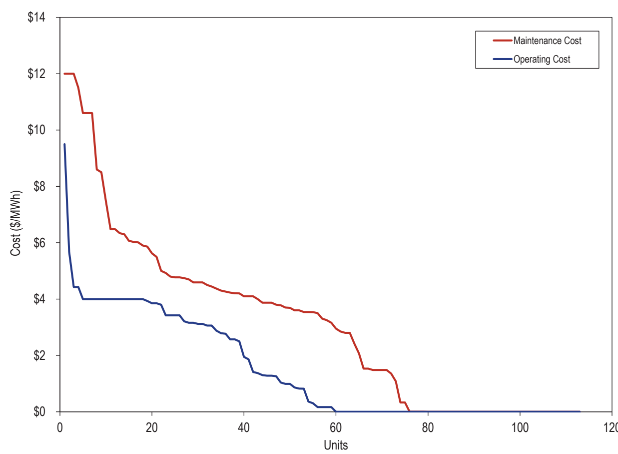


Figure 3-39 shows the PJM approved VOM costs for coal units, aggregated and converted into dollars per MWh. The variable operations costs are equal to short run marginal costs while variable maintenance costs are not. The average variable operations cost approved by PJM for coal units was $1.47 per MWh (the MMU benchmark for a new entrant coal unit is $4.03 per MWh). The average variable maintenance cost approved by PJM for coal units was $3.14 per MWh. The main reason for the difference between the MMU short run marginal cost benchmark and the average operations costs approved by PJM is that some participants include operations costs such as fuel handling, chemicals and ash disposal as other fuel related costs. Other fuel related costs are not approved by PJM as VOM costs, the method of calculating other fuel related costs are approved as part of the Fuel Cost Policy.

Figure 3-39 PJM approved variable operations and maintenance (VOM) costs for coal units: 2018



High VOM levels allow generators to economically withhold energy and to exercise market power even when offers are set to cost to mitigate market power. The MMU recommendation to limit cost-based offers to short run marginal costs would prevent such withholding. When units are not committed due to high VOM costs and instead a unit with higher short run marginal costs is committed, the market outcome is inefficient. When units that fail the TPS test are committed on their price-based offer when their short run marginal cost is lower, the market outcome is inefficient.

FERC System of Accounts

PJM Manual 15 relies on the FERC System of Accounts, which predates markets and does not define costs consistently with market economics.

The MMU recommends removal of all use of the FERC System of Accounts in PJM Manual 15.

Cyclic Starting and Peaking Factors

The use of cyclic starting and peaking factors for calculating VOM costs for combined cycles and combustion turbines is designed to allocate a greater proportion of long term maintenance costs to starts and the tail block of the incremental offer curve. The use of such factors is not appropriate given that long term maintenance costs are not short run marginal costs and should not be included in cost offers. PJM Manual 15 allows for a peaking cyclic factor of three, which means that a unit with a $300 per hour (EOH) VOM cost can add $180 per MWh to a 5 MW peak segment.[86]

The MMU recommends the removal of all cyclic starting and peaking factors from PJM Manual 15.

Labor Costs

PJM Manual 15 allows for the inclusion of plant staffing costs in energy market cost offers. This is inappropriate given that labor costs are not short run marginal costs.

The MMU recommends the removal of all labor costs from the PJM Manual 15.

Combined Cycle Start Heat Input Definition

PJM Manual 15 defines the start heat input of combined cycles as the amount of fuel used from the firing of the first combustion turbine to the close of the steam turbine breaker plus any fuel used by other combustion turbines in the combined cycle from firing to the point at which the HRSG steam pressure matches the steam turbine steam pressure. This definition is inappropriate given that after each combustion turbine is synchronized, some of the fuel is used to produce energy for which the resource is compensated in the energy market. To account for this, PJM Manual 15 requires reducing the station service MWh used during the start sequence by the output in MWh produced by each combustion turbine after synchronization and before the HRSG steam pressure matches the steam turbine steam pressure. The formula and the language in this definition are not appropriate and are unclear.

The MMU 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. This change will make the treatment of combined cycles consistent with steam turbines. Exceptions to this definition should be granted when the amount of fuel used from synchronization to steam turbine breaker close is greater than the no load heat plus the output during this period times the incremental heat rate.

Nuclear Costs

The fuel costs for nuclear plants are fixed in the short run and amortized over the period between refueling outages. The short run marginal cost of fuel for nuclear plants is zero. Operations and maintenance costs for nuclear power plants consist primarily of labor and maintenance costs incurred during outages, which are also fixed in the short run.

The MMU recommends the removal of nuclear fuel and nonfuel operations and maintenance costs that are not short run marginal costs from the PJM Manual 15.

Pumped Hydro Costs

The calculation of pumped hydro costs for energy storage in Section 7.3 of PJM Manual 15 is inaccurate. The mathematical formulation contains an error in the calculation of the weighted average pumping cost, and it does not take into account the purchase of power for pumping in the day-ahead market.

The MMU recommends revising the pumped hydro fuel cost calculation to include day-ahead and real-time power purchases.

Energy Market Opportunity Costs

The calculation of energy market opportunity costs for energy limited units in Section 12 of PJM Manual 15 fails to account for a number of physical unit characteristics and environmental restrictions that influence opportunity costs. These include start up time, notification time, minimum down time, multiple

86 The peak adder is equal to $300 times three divided by 5 MW.

fuel capability, multiple emissions limitations, and fuel usage limitations.

The MMU recommends revisions to the calculation of energy market opportunity costs to incorporate all time based offer parameters and all limitations that affect the opportunity cost of generating unit output.

The use of Catastrophic Force Majeure as the criterion for the use of opportunity costs for fuel supply limitations in Schedule 2 of the Operating Agreement is overly restrictive. This criterion would not allow the use of opportunity costs to allocate limited fuel in the case of regional fuel transportation disruptions or extreme weather events.

The MMU recommends removing the catastrophic designation for force majeure fuel supply limitations in Schedule 2.

Frequently Mitigated Units (FMU) and Associated Units (AU)

An FMU is a frequently mitigated unit. The results reported here include units that were mitigated for any reason, including both structural market power in the energy market and units called on for reliability reasons, including reactive and black start service.

The FMU adder was filed with FERC in 2005, and approved effective February 2006.[87] The goal, in 2005, was to ensure that units that were offer capped for most of their run hours could cover their going forward or avoidable costs (also known as ACR in the PJM Capacity Market). That function became unnecessary with the introduction of the RPM capacity market design in 2007. Units have the opportunity to recover ACR in the capacity market.

For those reasons, the MMU recommended the elimination of FMU and AU adders.[88] FMU and AU adders no longer serve the purpose for which they were created and interfere with the efficient operation of PJM markets.

The rules governing FMU and AU adders significantly changed on November 1, 2014.[89]

The definition of FMUs provides for a set of graduated adders associated with increasing levels of offer capping. Units capped for 60 percent or more of their run hours and less than 70 percent are eligible for an adder of either 10 percent of their cost-based offer or $20 per MWh. Units capped for 70 percent or more of their run hours and less than 80 percent are eligible for an adder of either 10 percent of their cost-based offer or $30 per MWh. Units capped for 80 percent or more of their run hours are eligible for an adder of either 10 percent of their cost-based offer or $40 per MWh. These categories are designated Tier 1, Tier 2 and Tier 3.

In addition to being offer capped for the designated percent of run hours, in order to qualify for an FMU adder, a generating unit's Projected PJM Market Revenues plus the unit's PJM capacity market revenues on a rolling 12-month basis, divided by the unit's MW of installed capacity (in $/MW-year) must be less than its accepted unit specific Avoidable Cost Rate (in $/MW-year) (excluding APIR and ARPIR), or its default Avoidable Cost Rate (in $/MW-year) if no unit-specific Avoidable Cost Rate is accepted for the BRAs for the delivery years included in the rolling 12-month period, determined pursuant to Sections 6.7 and 6.8 of Attachment DD of the Tariff. (The relevant Avoidable Cost Rate is the weighted average of the Avoidable Cost Rates for each Delivery Year included in the rolling 12-month period, weighted by month.) No portion of the unit may be included in an FRR capacity plan or be receiving compensation under Part V of the PJM Tariff and the unit must be internal to the PJM Region and subject only to PJM dispatch.[90]

An AU, or associated unit, is a unit that is physically, electrically and economically identical to an FMU, but does not qualify for the same FMU adder based on the number of run-hours the unit is offer capped.[91] For example, if a generating station had two identical units

87 110 FERC ¶ 61,053 (2005).

88 See the "*FMU Problem Statement and Issue Charge*," MIC <http://www.monitoringanalytics.com/reports/Presentations/2013/IMM_MIC_FMU_Problem_Statement_and_Issue_Charge_20130306.pdf>.

89 The MMU and PJM proposed a compromise on the elimination of FMU adders that maintains the ability of generating units to qualify for FMU adders when units have net revenues less than unit going forward costs or ACR. PJM submitted the joint MMU/PJM proposal to the Commission pursuant to section 206 of the Federal Power Act. On October 31, 2014, the Commission conditionally approved the filing and the new rule became effective November 1, 2014, with the conditions addressed.

90 PJM Operating Agreement Schedule 1 § 6.4.2.

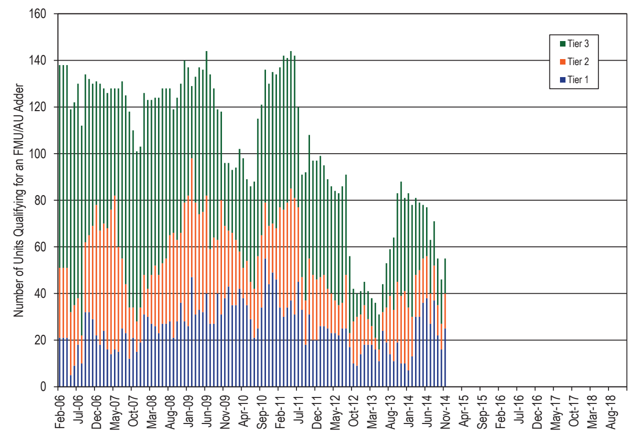
91 An associated unit (AU) must belong to the same design class (where a design class includes generation that is the same size and uses the same technology, without regard to manufacturer) and uses the identical primary fuel as the FMU.

with identical electrical impacts on the system, one of which was offer capped for more than 80 percent of its run hours, that unit would be designated a Tier 3 FMU. If the second unit were capped for 30 percent of its run hours, that unit would be an AU and receive the same Tier 3 adder as the FMU at the site. The AU designation was implemented to ensure that the associated unit is not dispatched in place of the FMU, resulting in no effective adder for the FMU. In the absence of the AU designation, the associated unit would be an FMU after its dispatch and the FMU would be dispatched in its place after losing its FMU designation.

Effective in planning year 2020/2021, default Avoidable Cost Rates will no longer be defined. If a generating unit's Projected PJM Market Revenues plus the unit's PJM capacity market revenues on a rolling 12-month basis (in $/MW-year) are greater than zero, and if the generating unit does not have an approved unit specific Avoidable Cost Rate, the generating unit will not qualify as an FMU as the Avoidable Cost Rate will be assumed to be zero for FMU qualification purposes.

Figure 3-40 shows the total number of FMUs and AUs that qualified for an adder since the inception of the business rule in February 2006. The new rules for determining the qualification of a unit as an FMU or AU became effective November 1, 2014. FMUs and AUs are designated monthly, and a unit's capping percentage is based on a rolling 12 month average, effective with a one-month lag.[92] The number of units that were eligible for an FMU or AU adder declined from an average of 70 units during the first 11 months of 2014, to zero since December 2014.

Figure 3-40 Frequently mitigated units and associated units (By month): February 2006 through 2018



Virtual Offers and Bids

There is a substantial volume of virtual offers and bids in the PJM Day-Ahead Energy Market and such offers and bids may be marginal, based on the way in which the PJM market clearing algorithm works.

Any market participant in the PJM Day-Ahead Energy Market can use increment offers, decrement bids, up to congestion transactions, import transactions and export transactions as financial instruments that do not require physical generation or load. Increment offers and decrement bids may be submitted at any hub, transmission zone, aggregate, or single bus for which LMP is calculated. On February 20, 2018, FERC issued an order limiting the eligible bidding points for up to congestion transactions to hubs, residual metered load and interfaces.[93] Up to congestion transactions may be submitted between any two buses on a list of 49 buses, eligible for up to congestion transaction bidding.[94] Import and export transactions may be submitted at any interface pricing point, where an import is equivalent to a virtual offer that is injected into PJM and an export is equivalent to a virtual bid that is withdrawn from PJM.

Figure 3-41 shows the PJM day-ahead daily aggregate supply curve of increment offers, the system aggregate supply curve of imports, the system aggregate supply

92 PJM Operating Agreement Schedule 1 § 6.4.2. In 2007, the FERC approved revisions to clarify the AU criteria.

93 162 FERC ¶ 61,139 (2018).

94 Market participants were required to specify an interface pricing point as the source for imports, an interface pricing point as the sink for exports or an interface pricing point as both the source and sink for transactions wheeling through PJM. On November 1, 2012, PJM eliminated this requirement. For the list of eligible sources and sinks for up to congestion transactions, see www.pjm.com "*OASIS-Source-Sink-Link.xls*," <http://www.pjm.com/~/media/etools/oasis/references/oasis-source-sink-link.ashx>.

curve without increment offers and imports, the system aggregate supply curve with increment offers, and the system aggregate supply curve with increment offers and imports for an example day in 2017.

Figure 3-41 Day-ahead aggregate supply curves: 2017 example day

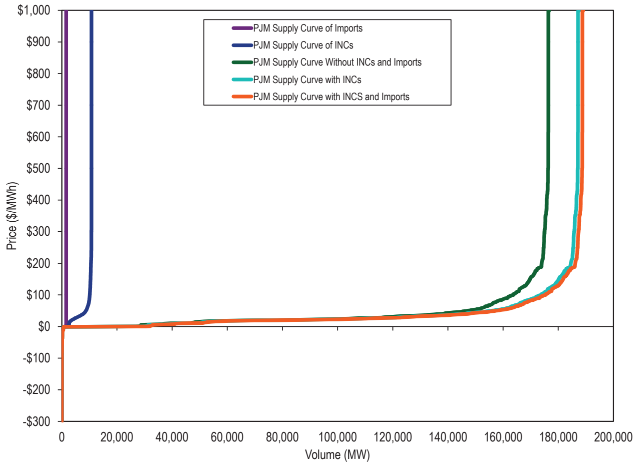


Figure 3-42 shows example PJM day-ahead aggregate supply curves for the typical dispatch price range.

Figure 3-42 Typical dispatch price range for day-ahead aggregate supply curves: 2017 example day

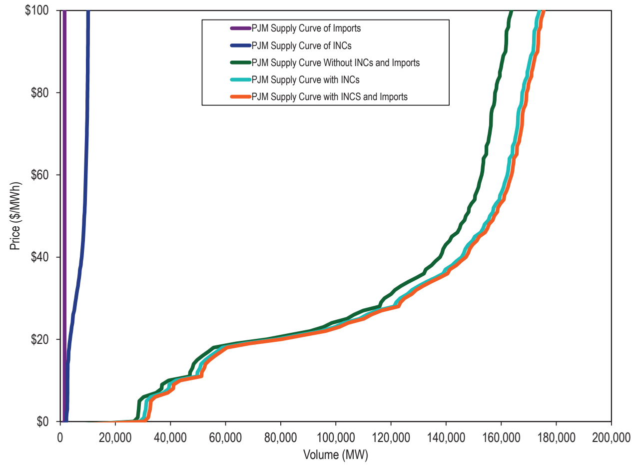


Table 3-44 shows the hourly average number of cleared and submitted increment offers and decrement bids by month in January 2017 through December 2018. The hourly average submitted and cleared increment MW decreased by 27.5 percent and 41.3 percent, from 7,968 MW and 4,562 MW in 2017 to 5,776 MW and 2,676 MW in 2018. The hourly average submitted and cleared decrement MW decreased by 14.2 percent and 28.0 percent, from 7,874 MW and 4,035 MW in 2017 to 6,753 MW and 2,906 MW in 2018.

Table 3-44 Average hourly number of cleared and submitted INCs and DECs by month: January 2017 through December 2018

		Increment Offers				Decrement Bids			
Year		Average Cleared MW	Average Submitted MW	Average Cleared Volume	Average Submitted Volume	Average Cleared MW	Average Submitted MW	Average Cleared Volume	Average Submitted Volume
2017	Jan	5,855	10,169	205	1,288	4,811	9,753	136	821
2017	Feb	6,058	10,590	266	1,430	4,599	9,326	149	784
2017	Mar	6,427	10,516	312	1,669	5,170	9,915	170	1,019
2017	Apr	5,115	8,860	280	1,401	5,139	8,986	178	776
2017	May	5,643	9,724	278	1,286	5,030	9,188	164	768
2017	Jun	3,961	7,705	193	1,153	4,314	8,257	173	831
2017	Jul	3,921	7,087	233	1,014	3,807	7,828	167	779
2017	Aug	3,418	5,951	279	1,022	3,209	5,845	169	593
2017	Sep	3,537	6,201	190	919	3,502	6,076	139	603
2017	Oct	3,927	6,498	309	1,128	3,111	6,008	168	586
2017	Nov	3,558	6,454	290	1,240	2,632	5,970	179	683
2017	Dec	3,404	6,029	234	1,102	3,138	7,400	177	793
2017	Annual	4,562	7,968	256	1,220	4,035	7,874	164	753
2018	Jan	2,903	6,834	293	1,387	2,728	8,782	196	1,188
2018	Feb	2,519	5,415	280	1,160	2,418	5,857	136	634
2018	Mar	2,790	5,985	521	1,266	2,580	7,020	330	978
2018	Apr	3,060	5,848	222	792	2,555	6,919	197	801
2018	May	2,892	5,563	168	650	3,158	6,684	154	662
2018	Jun	2,444	5,601	142	662	3,041	6,460	147	609
2018	Jul	1,829	4,984	130	642	2,721	6,028	145	622
2018	Aug	2,114	5,214	179	744	2,821	6,439	144	618
2018	Sep	2,653	6,252	192	803	3,619	7,631	171	674
2018	Oct	3,230	6,328	281	1,021	3,106	6,714	162	788
2018	Nov	3,260	5,981	287	958	3,020	6,419	154	818
2018	Dec	2,428	5,293	242	951	3,080	6,008	169	736
2018	Annual	2,676	5,776	245	919	2,906	6,753	176	762

Table 3-45 shows the average hourly number of up to congestion transactions and the average hourly MW in January 2017 through December 2018. In 2018, the average hourly up to congestion submitted and cleared MW decreased by 57.3 percent and 48.7 percent, compared to 2017.

Table 3-45 Average hourly cleared and submitted up to congestion bids by month: January 2017 through December 2018

		Up to Congestion			
Year		Average Cleared MW	Average Submitted MW	Average Cleared Volume	Average Submitted Volume
2017	Jan	39,639	196,472	2,466	10,246
2017	Feb	38,814	207,994	2,091	8,309
2017	Mar	31,817	164,063	1,703	6,252
2017	Apr	29,212	152,868	2,689	6,022
2017	May	32,883	116,688	2,977	4,957
2017	Jun	35,469	112,071	2,528	4,839
2017	Jul	37,668	118,609	2,413	5,108
2017	Aug	32,986	122,677	2,294	5,062
2017	Sep	29,368	120,956	2,309	4,423
2017	Oct	28,250	117,486	2,612	4,745
2017	Nov	36,506	110,325	2,927	4,679
2017	Dec	40,090	113,992	3,552	4,749
2017	Annual	34,387	137,419	2,549	5,770
2018	Jan	31,066	124,101	2,174	6,511
2018	Feb	25,543	94,687	1,857	4,703
2018	Mar	8,990	28,008	733	1,969
2018	Apr	11,930	43,989	877	2,001
2018	May	15,592	50,133	895	2,120
2018	Jun	15,227	46,207	827	1,794
2018	Jul	17,008	49,075	1,102	2,486
2018	Aug	17,658	53,077	997	2,317
2018	Sep	16,180	53,171	856	1,949
2018	Oct	16,284	49,862	939	2,115
2018	Nov	18,027	58,069	1,035	2,173
2018	Dec	18,446	55,795	1,152	2,254
2018	Annual	17,624	58,650	1,117	2,691

Table 3-46 shows the average hourly number of import and export transactions and the average hourly MW in January 2017 through December 2018. In 2018, the average hourly submitted and cleared import transaction MW decreased by 28.4 and 34.3 percent, and the average hourly submitted and cleared export transaction MW decreased by 10.4 and 10.5 percent, compared to 2017. The large difference in net interchange volumes from 2017 to 2018 was primarily a result of the requirement for external capacity resources to be pseudo tied into PJM with the result that import MWh became internal MWh.[95]

Table 3-46 Hourly average day-ahead number of cleared and submitted import and export transactions by month: January 2017 through December 2018

		Imports				Exports			
Year	Month	Average Cleared MW	Average Submitted MW	Average Cleared Volume	Average Submitted Volume	Average Cleared MW	Average Submitted MW	Average Cleared Volume	Average Submitted Volume
2017	Jan	1,465	1,505	8	9	3,842	3,855	20	20
2017	Feb	1,379	1,418	7	8	3,546	3,558	19	19
2017	Mar	1,125	1,157	6	7	3,791	3,813	18	18
2017	Apr	614	621	5	5	3,050	3,070	16	16
2017	May	188	201	4	4	2,805	2,817	18	18
2017	Jun	248	255	3	4	2,705	2,730	16	16
2017	Jul	240	247	3	3	3,092	3,113	16	16
2017	Aug	158	168	2	3	2,401	2,410	12	13
2017	Sep	233	237	3	4	2,884	2,903	14	15
2017	Oct	211	218	3	3	2,293	2,301	12	12
2017	Nov	337	362	3	4	1,998	2,010	10	10
2017	Dec	324	386	3	5	3,193	3,245	15	15
2017	Annual	539	560	4	5	2,965	2,984	15	16
2018	Jan	541	640	8	10	2,531	2,567	13	13
2018	Feb	556	809	7	11	2,778	2,853	14	14
2018	Mar	578	612	7	8	1,895	1,892	10	11
2018	Apr	486	514	6	7	2,150	2,168	11	11
2018	May	382	404	5	6	2,495	2,506	15	15
2018	Jun	246	254	4	4	3,197	3,222	19	19
2018	Jul	260	286	4	5	3,014	3,027	15	15
2018	Aug	358	388	4	5	3,647	3,671	17	17
2018	Sep	230	244	4	4	3,384	3,390	17	17
2018	Oct	362	371	4	5	3,387	3,432	18	18
2018	Nov	501	533	7	7	2,037	1,992	13	13
2018	Dec	453	518	7	8	3,030	3,035	18	18
2018	Annual	412	462	6	7	2,797	2,814	15	15

Table 3-47 shows the frequency with which generation offers, import or export transactions, up to congestion transactions, decrement bids, increment offers and price-sensitive demand were marginal in 2017 and 2018.

95 See *2018 State of the Market Report for PJM*, Section 9: Interchange Transactions, Figure 9-1.

Table 3-47 Type of day-ahead marginal resources: 2017 and 2018

	2017						2018					
	Generation	Dispatchable Transaction	Up to Congestion Transaction	Decrement Bid	Increment Offer	Price Sensitive Demand	Generation	Dispatchable Transaction	Up to Congestion Transaction	Decrement Bid	Increment Offer	Price Sensitive Demand
Jan	3.2%	0.0%	85.3%	7.7%	3.7%	0.0%	5.3%	0.1%	82.5%	7.4%	4.6%	0.0%
Feb	4.9%	0.0%	83.9%	6.5%	4.6%	0.0%	5.9%	0.1%	80.8%	9.1%	4.0%	0.0%
Mar	4.3%	0.1%	81.5%	8.5%	5.6%	0.0%	17.2%	0.2%	47.0%	20.4%	15.2%	0.0%
Apr	2.8%	0.0%	83.4%	8.9%	4.9%	0.0%	13.5%	0.1%	45.7%	24.1%	16.6%	0.0%
May	3.5%	0.0%	77.4%	11.8%	7.2%	0.0%	15.2%	0.1%	49.6%	24.0%	11.1%	0.0%
Jun	4.3%	0.0%	73.5%	15.4%	6.7%	0.0%	15.3%	0.1%	54.5%	20.8%	9.3%	0.0%
Jul	2.9%	0.0%	77.1%	13.6%	6.4%	0.0%	12.4%	0.1%	57.8%	19.0%	10.6%	0.1%
Aug	3.8%	0.0%	81.8%	9.0%	5.4%	0.0%	11.1%	0.2%	54.5%	22.5%	11.7%	0.0%
Sep	6.6%	0.0%	77.8%	9.8%	5.8%	0.0%	15.1%	0.2%	50.7%	20.5%	13.5%	0.0%
Oct	6.3%	0.0%	77.7%	10.3%	5.7%	0.0%	12.7%	0.2%	54.3%	19.7%	13.0%	0.0%
Nov	5.1%	0.1%	78.7%	10.6%	5.6%	0.0%	10.2%	0.1%	56.1%	20.3%	13.2%	0.0%
Dec	4.9%	0.1%	78.9%	10.8%	5.3%	0.0%	12.1%	0.1%	58.3%	20.4%	9.1%	0.0%
Annual	4.3%	0.0%	79.9%	10.2%	5.5%	0.0%	10.9%	0.1%	62.3%	16.9%	9.8%	0.0%

Figure 3-43 shows the monthly volume of bid and cleared INC, DEC and up to congestion bids by month from January 2005, through December 2018.

Figure 3-43 Monthly bid and cleared INCs, DECs and UTCs (MW): January 2005 through December 2018

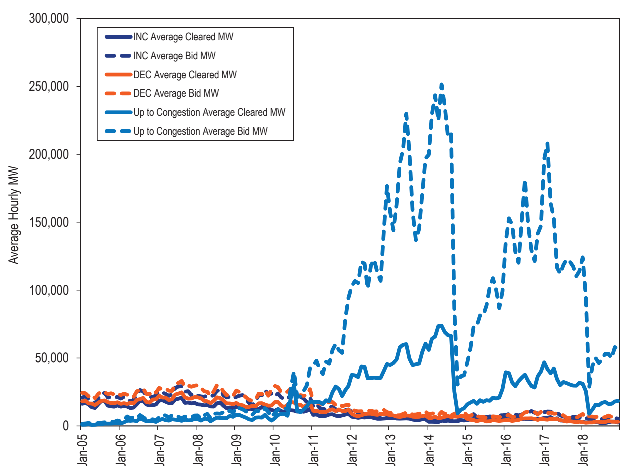
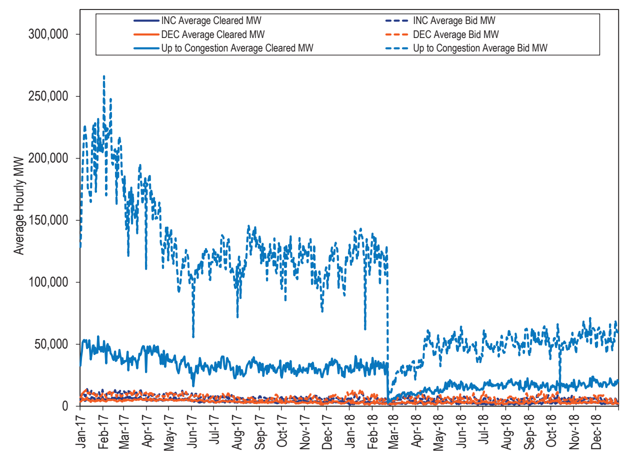


Figure 3-44 shows the daily volume of bid and cleared INC, DEC and up to congestion bids from January 1, 2017 through December 31, 2018.

Figure 3-44 Daily bid and cleared INCs, DECs, and UTCs (MW): January 2017 through December 2018



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

Table 3-48 shows, in 2017 and 2018, the total increment offers and decrement bids and cleared MW by type of parent organization.

Table 3-48 INC and DEC bids and cleared MWh by type of parent organization (MWh): 2017 and 2018

	2017				2018			
Category	Total Virtual Bid MWh	Percent	Total Virtual Cleared MWh	Percent	Total Virtual Bid MWh	Percent	Total Virtual Cleared MWh	Percent
Financial	98,457,022	71.0%	44,577,468	59.2%	93,482,557	85.2%	39,357,836	80.5%
Physical	40,307,159	29.0%	30,728,320	40.8%	16,269,802	14.8%	9,542,265	19.5%
Total	138,764,180	100.0%	75,305,788	100.0%	109,752,359	100.0%	48,900,101	100.0%

Table 3-49 shows, in 2017 and 2018, the total up to congestion bids and cleared MWh by type of parent organization.

Table 3-49 Up to congestion transactions by type of parent organization (MWh): 2017 and 2018

	2017				2018			
Category	Total Up to Congestion Bid MWh	Percent	Total Up to Congestion Cleared MWh	Percent	Total Up to Congestion Bid MWh	Percent	Total Up to Congestion Cleared MWh	Percent
Financial	1,142,283,154	94.9%	283,434,835	92.6%	505,934,059	98.5%	148,334,212	96.1%
Physical	61,503,398	5.1%	22,529,428	7.4%	7,838,021	1.5%	6,053,802	3.9%
Total	1,203,786,552	100.0%	305,964,263	100.0%	513,772,079	100.0%	154,388,014	100.0%

Table 3-50 shows, in 2017 and 2018, the total import and export transactions by whether the parent organization was financial or physical.

Table 3-50 Import and export transactions by type of parent organization (MW): 2017 and 2018

		2017		2018	
	Category	Total Import and Export MW	Percent	Total Import and Export MW	Percent
Day-Ahead	Financial	11,402,508	37.2%	7,518,237	26.8%
	Physical	19,275,555	62.8%	20,565,279	73.2%
	Total	30,678,064	100.0%	28,083,517	100.0%
Real-Time	Financial	19,528,399	36.1%	11,111,799	21.4%
	Physical	34,550,062	63.9%	40,713,343	78.6%
	Total	54,078,461	100.0%	51,825,142	100.0%

Table 3-51 shows increment offers and decrement bids by top 10 locations in 2017 and 2018.

Table 3-51 Virtual offers and bids by top 10 locations (MW): 2017 and 2018

2017					2018				
Aggregate/Bus Name	Aggregate/ Bus Type	INC MW	DEC MW	Total MW	Aggregate/Bus Name	Aggregate/Bus Type	INC MW	DEC MW	Total MW
WESTERN HUB	HUB	19,470,362	13,886,396	33,356,758	WESTERN HUB	HUB	3,602,714	2,478,033	6,080,747
MISO	INTERFACE	298,749	5,702,665	6,001,414	MISO	INTERFACE	264,103	2,486,692	2,750,795
AEP-DAYTON HUB	HUB	2,281,775	670,706	2,952,481	NYIS	INTERFACE	1,388,940	1,162,120	2,551,060
NYIS	INTERFACE	1,567,702	1,353,652	2,921,355	SOUTHIMP	INTERFACE	2,245,054	0	2,245,054
N ILLINOIS HUB	HUB	595,931	1,917,519	2,513,450	DOM_RESID_AGG	RESIDUAL_METERED_EDC	467,704	1,187,251	1,654,955
SOUTHIMP	INTERFACE	2,156,932	0	2,156,932	BGE_RESID_AGG	RESIDUAL_METERED_EDC	312,185	1,312,996	1,625,181
DCKCRKCE345 KV UN1 DYN	GEN	1,331,426	773,672	2,105,098	DOMINION HUB	HUB	425,097	1,018,322	1,443,419
BGE	ZONE	417,037	1,384,137	1,801,174	N ILLINOIS HUB	HUB	559,116	873,949	1,433,065
FOWLER 34.5 KV FWLR1AWF	GEN	378,544	1,399,471	1,778,015	AEP-DAYTON HUB	HUB	579,459	810,391	1,389,851
PEPCO	ZONE	480,538	672,508	1,153,047	DCKCRKCE345 KV UN1 DYN	GEN	530,367	825,678	1,356,045
Top ten total		28,978,996	27,760,726	56,739,722			10,374,740	12,155,432	22,530,173
PJM total		69,794,286	68,969,894	138,764,180			50,612,238	59,325,627	109,937,865
Top ten total as percent of PJM total		41.5%	40.3%	40.9%			20.5%	20.5%	20.5%

Table 3-52 shows up to congestion transactions by import bids for the top 10 locations and associated profits at each path in 2017 and 2018.[96]

Table 3-52 Cleared up to congestion import bids by top 10 source and sink pairs (MW): 2017 and 2018

2017							
Imports							
Source	Source Type	Sink	Sink Type	MW	Source Profit	Sink Profit	UTC Profit
MISO	INTERFACE	COOK	EHVAGG	862,597	$530,817	($362,091)	$168,726
HUDSONTP	INTERFACE	LEONIA 230 T-2	AGGREGATE	716,396	($1,077,843)	$1,106,825	$28,981
NYIS	INTERFACE	PSEG	ZONE	440,185	$620,936	($674,473)	($53,537)
SOUTHEAST	INTERFACE	WEST INT HUB	HUB	431,218	$288,985	($234,984)	$54,002
OVEC	INTERFACE	DEOK	ZONE	414,137	$453,386	($338,163)	$115,223
SOUTHEAST	INTERFACE	VP KERR DAM 1-7	AGGREGATE	400,948	$790,018	($552,390)	$237,628
OVEC	INTERFACE	ATSI	ZONE	361,693	$125,111	$89,257	$214,368
SOUTHWEST	INTERFACE	COOK	EHVAGG	328,062	$579,239	($284,341)	$294,898
MISO	INTERFACE	AELC	AGGREGATE	289,641	$51,714	($34,635)	$17,079
NORTHWEST	INTERFACE	COMED	ZONE	273,133	$61,611	$103,176	$164,787
Top ten total				4,518,009	$2,423,975	($1,181,820)	$1,242,155
PJM total				22,394,654	$14,515,393	($11,183,972)	$3,331,421
Top ten total as percent of PJM total				20.2%	16.7%	10.6%	37.3%
2018							
Imports							
Source	Source Type	Sink	Sink Type	MW	Source Profit	Sink Profit	UTC Profit
NORTHWEST	INTERFACE	N ILLINOIS HUB	HUB	3,218,523	$1,691,707	($390,306)	$1,301,401
NORTHWEST	INTERFACE	CHICAGO GEN HUB	HUB	2,502,297	$1,371,313	($378,689)	$992,624
NORTHWEST	INTERFACE	COMED_RESID_AGG	AGGREGATE	1,698,384	$1,456,193	($998,428)	$457,764
OVEC	INTERFACE	DEOK_RESID_AGG	AGGREGATE	1,209,403	$472,392	($252,294)	$220,098
NORTHWEST	INTERFACE	CHICAGO HUB	HUB	1,011,450	$56,803	$154,141	$210,944
NEPTUNE	INTERFACE	JCPL_RESID_AGG	AGGREGATE	827,093	$526,013	($446,429)	$79,584
MISO	INTERFACE	CHICAGO GEN HUB	HUB	819,380	$476,813	$556,202	$1,033,015
OVEC	INTERFACE	AEP GEN HUB	HUB	818,713	$147,456	($24,718)	$122,738
MISO	INTERFACE	CHICAGO HUB	HUB	728,268	$454,788	$47,119	$501,907
MISO	INTERFACE	AEPIM_RESID_AGG	AGGREGATE	696,139	$575,937	($236,237)	$339,701
Top ten total				13,529,647	$7,229,416	($1,969,639)	$5,259,778
PJM total				32,994,068	$17,811,591	($7,194,678)	$10,616,913
Top ten total as percent of PJM total				41.0%	40.6%	27.4%	49.5%

96 The source and sink aggregates in these tables refer to the name and location of a bus and do not include information about the behavior of any individual market participant.

Table 3-53 shows up to congestion transactions by export bids for the top 10 locations and associated profits at each path in 2017 and 2018.

Table 3-53 Cleared up to congestion export bids by top 10 source and sink pairs (MW): 2017 and 2018

				2017			
				Exports			
Source	Source Type	Sink	Sink Type	MW	Source Profit	Sink Profit	UTC Profit
JEFFERSON	EHVAGG	SOUTHWEST	INTERFACE	958,719	$1,105,168	($832,337)	$272,832
COMED	ZONE	NIPSCO	INTERFACE	902,140	$213,294	$753,759	$967,053
21 KINCA ATR24304	AGGREGATE	SOUTHWEST	INTERFACE	885,041	$420,564	($337,615)	$82,949
SULLIVAN-AEP	EHVAGG	SOUTHWEST	INTERFACE	596,031	$201,669	($114,584)	$87,085
POWERTON 5	AGGREGATE	NORTHWEST	INTERFACE	467,263	($130,278)	$93,241	($37,037)
JEFFERSON	EHVAGG	NIPSCO	INTERFACE	440,544	$511,047	($307,845)	$203,202
ROCKPORT	EHVAGG	SOUTHWEST	INTERFACE	409,795	$205,091	($191,932)	$13,159
21 KINCA ATR24304	AGGREGATE	NIPSCO	INTERFACE	368,921	$102,909	($48,839)	$54,070
STMARYSGEN	AGGREGATE	NIPSCO	INTERFACE	364,289	$391,159	($414,341)	($23,182)
NAGELAEP	EHVAGG	SOUTHWEST	INTERFACE	315,139	$185,106	($95,591)	$89,515
Top ten total				5,707,881	$3,205,729	($1,496,083)	$1,709,646
PJM total				20,710,413	$6,965,558	$321,519	$7,287,077
Top ten total as percent of PJM total				27.6%	46.0%	(465.3%)	23.5%
				2018			
				Exports			
Source	Source Type	Sink	Sink Type	MW	Source Profit	Sink Profit	UTC Profit
CHICAGO GEN HUB	HUB	NIPSCO	INTERFACE	851,242	$1,161,567	($71,626)	$1,089,941
COMED_RESID_AGG	AGGREGATE	NIPSCO	INTERFACE	843,975	$1,535,785	($54,344)	$1,481,441
N ILLINOIS HUB	HUB	NIPSCO	INTERFACE	752,858	$1,176,338	($120,908)	$1,055,430
JCPL_RESID_AGG	AGGREGATE	HUDSONTP	INTERFACE	434,729	($32,561)	($215,015)	($247,576)
CHICAGO HUB	HUB	NIPSCO	INTERFACE	348,659	$1,229,743	($621,890)	$607,853
N ILLINOIS HUB	HUB	NORTHWEST	INTERFACE	341,272	$574,382	($270,960)	$303,422
CHICAGO HUB	HUB	NORTHWEST	INTERFACE	248,495	$426,510	($194,784)	$231,726
OHIO HUB	HUB	NIPSCO	INTERFACE	236,208	($91,824)	$48,014	($43,810)
CHICAGO GEN HUB	HUB	NORTHWEST	INTERFACE	234,988	$350,564	($286,317)	$64,247
OVEC	ZONE	SOUTHEXP	INTERFACE	212,623	$389,869	($271,549)	$118,320
Top ten total				4,505,049	$6,720,373	($2,059,380)	$4,660,993
PJM total				13,250,859	$3,341,683	$1,828,951	$5,170,634
Top ten total as percent of PJM total				34.0%	201.1%	(112.6%)	90.1%

Table 3-54 shows up to congestion transactions by wheel bids and associated profits at each path for the top 10 locations in 2017 and 2018.

Table 3-54 Cleared up to congestion wheel bids by top 10 source and sink pairs (MW): 2017 and 2018

				2017			
				Wheels			
Source	Source Type	Sink	Sink Type	MW	Source Profit	Sink Profit	UTC Profit
MISO	INTERFACE	NIPSCO	INTERFACE	312,671	$373,405	($178,579)	$194,827
MISO	INTERFACE	NORTHWEST	INTERFACE	290,558	$254,925	($157,891)	$97,035
SOUTHWEST	INTERFACE	SOUTHEXP	INTERFACE	249,976	$572,074	($618,373)	($46,298)
NORTHWEST	INTERFACE	MISO	INTERFACE	245,473	$207,111	($48,206)	$158,905
SOUTHWEST	INTERFACE	NIPSCO	INTERFACE	78,378	$96,395	($31,898)	$64,497
NORTHWEST	INTERFACE	NIPSCO	INTERFACE	66,895	$11,965	$88,301	$100,266
OVEC	INTERFACE	SOUTHWEST	INTERFACE	42,037	$44,820	($47,195)	($2,375)
OVEC	INTERFACE	MISO	INTERFACE	37,097	$6,134	$1,438	$7,572
SOUTHEAST	INTERFACE	SOUTHEXP	INTERFACE	34,280	$11,127	$5,177	$16,304
SOUTHEAST	INTERFACE	NORTHWEST	INTERFACE	22,300	$28,198	$54,892	$83,090
Top ten total				1,379,663	$1,606,156	($932,332)	$673,823
PJM total				1,652,065	$1,637,231	($973,154)	$664,077
Top ten total as percent of PJM total				83.5%	98.1%	95.8%	101.5%
				2018			
				Wheels			
Source	Source Type	Sink	Sink Type	MW	Source Profit	Sink Profit	UTC Profit
MISO	INTERFACE	NIPSCO	INTERFACE	1,268,344	$2,184,421	($535,087)	$1,649,335
MISO	INTERFACE	NORTHWEST	INTERFACE	1,175,782	$824,529	$149,250	$973,780
NORTHWEST	INTERFACE	MISO	INTERFACE	636,283	$910,615	($426,866)	$483,749
NORTHWEST	INTERFACE	NIPSCO	INTERFACE	334,065	$419,037	$346,497	$765,534
MISO	INTERFACE	SOUTHEXP	INTERFACE	332,961	$518,758	($312,863)	$205,895
SOUTHIMP	INTERFACE	NIPSCO	INTERFACE	287,183	($264,459)	$729,817	$465,358
SOUTHIMP	INTERFACE	OVEC	INTERFACE	220,935	($1,236,367)	$1,172,358	($64,009)
OVEC	INTERFACE	SOUTHEXP	INTERFACE	191,347	$363,908	($263,332)	$100,576
SOUTHIMP	INTERFACE	MISO	INTERFACE	162,335	($152,694)	$142,419	($10,275)
MISO	INTERFACE	OVEC	INTERFACE	155,611	$63,404	($28,758)	$34,646
Top ten total				4,764,846	$3,631,152	$973,436	$4,604,588
PJM total				6,608,284	$4,709,423	$210,932	$4,920,355
Top ten total as percent of PJM total				72.1%	77.1%	461.5%	93.6%

On November 1, 2012, PJM eliminated the requirement for market participants to specify an interface pricing point as either the source or sink of an up to congestion transaction. The top 10 internal up to congestion transaction locations were 11.9 percent of the PJM total internal up to congestion transactions MW in 2018.

Table 3-55 shows up to congestion transactions by internal bids for the top 10 locations and associated profits at each path in 2017 and 2018. The total UTC profit by top 10 locations decreased by $0.8 million, from $2.9 million in 2017 to $2.1 million in 2018. The total internal cleared MW decreased by 159.7 million MW, or 61.1 percent, from 261.2 million MW in 2017 to 101.5 million MW in 2018.

Table 3-55 Cleared up to congestion internal bids by top 10 source and sink pairs (MW): 2017 and 2018

2017							
Internal							
Source	Source Type	Sink	Sink Type	MW	Source Profit	Sink Profit	UTC Profit
DUMONT	EHVAGG	COOK	EHVAGG	2,543,775	$1,574,512	($1,246,431)	$328,081
STUART 3	AGGREGATE	MICHFE	AGGREGATE	1,669,383	$658,096	($62,625)	$595,471
DAY	ZONE	BUCKEYE - DPL	AGGREGATE	1,598,133	$726,065	($528,828)	$197,237
AEP-DAYTON HUB	HUB	N ILLINOIS HUB	HUB	1,525,047	$474,692	($16,762)	$457,930
BAKER	EHVAGG	AMP-OHIO	AGGREGATE	1,342,005	$648,116	($254,350)	$393,767
FE GEN	AGGREGATE	ATSI	ZONE	1,327,118	($51,472)	$239,827	$188,355
JEFFERSON	EHVAGG	OHIO HUB	HUB	1,302,743	$1,079,684	($695,857)	$383,827
WINNETKA	AGGREGATE	CHICAGO HUB	HUB	1,110,026	$279,842	($154,257)	$125,585
WAUKEGAN TR412	AGGREGATE	KENDALL 1-2	AGGREGATE	1,093,269	$206,011	($47,976)	$158,036
ELWOOD 5	AGGREGATE	KENDALL 1-2	AGGREGATE	1,021,633	$212,292	($116,383)	$95,909
Top ten total				14,533,132	$5,807,839	($2,883,640)	$2,924,199
PJM total				261,207,130	$83,701,553	($40,113,288)	$43,588,265
Top ten total as percent of PJM total				5.6%	6.9%	7.2%	6.7%
2018							
Internal							
Source	Source Type	Sink	Sink Type	MW	Source Profit	Sink Profit	UTC Profit
WESTERN HUB	HUB	N ILLINOIS HUB	HUB	1,779,245	$1,446,947	($1,812,101)	($365,154)
SMECO_RESID_AGG	AGGREGATE	BGE_RESID_AGG	AGGREGATE	1,382,512	$969,902	($702,017)	$267,885
AEP GEN HUB	HUB	AEPOHIO_RESID_AGG	AGGREGATE	1,279,403	$492,063	($136,415)	$355,647
AEP GEN HUB	HUB	FEOHIO_RESID_AGG	AGGREGATE	1,176,283	$942,169	($166,998)	$775,171
WESTERN HUB	HUB	AEP-DAYTON HUB	HUB	1,019,828	$329,608	($193,173)	$136,435
AEP GEN HUB	HUB	ATSI GEN HUB	HUB	914,143	$516,765	$248,699	$765,464
CHICAGO HUB	HUB	COMED_RESID_AGG	AGGREGATE	901,297	$963,750	($864,246)	$99,505
AEP GEN HUB	HUB	AEP-DAYTON HUB	HUB	881,501	$550,556	($499,384)	$51,172
AECO_RESID_AGG	AGGREGATE	VINELAND_RESID_AGG	AGGREGATE	878,373	($381,373)	$400,938	$19,565
DOM_RESID_AGG	AGGREGATE	DOMINION HUB	HUB	793,092	$1,485,335	($1,495,735)	($10,400)
Top ten total				11,005,677	$7,315,722	($5,220,433)	$2,095,289
PJM total				101,534,802	$16,489,602	$1,175,932	$17,665,535
Top ten total as percent of PJM total				10.8%	44.4%	(443.9%)	11.9%

Table 3-56 shows the number of source-sink pairs that were offered and cleared monthly for January 1, 2017 through December 31, 2018.

Table 3-56 Number of offered and cleared source and sink pairs: January 2017 through December 2018

		Daily Number of Source-Sink Pairs			
Year	Month	Average Offered	Max Offered	Average Cleared	Max Cleared
2017	Jan	11,893	13,258	7,785	8,839
2017	Feb	9,337	11,902	6,756	7,758
2017	Mar	7,795	8,776	6,051	7,001
2017	Apr	8,168	8,805	6,494	7,172
2017	May	7,936	9,117	6,477	7,294
2017	Jun	9,776	13,012	5,822	6,228
2017	Jul	12,726	13,334	5,960	6,481
2017	Aug	12,966	15,729	6,578	7,201
2017	Sep	7,758	9,229	6,030	7,162
2017	Oct	8,540	9,432	6,507	7,189
2017	Nov	8,027	9,665	6,273	7,444
2017	Dec	7,782	8,872	5,892	6,771
2017	Annual	9,392	10,928	6,385	7,212
2018	Jan	7,983	8,492	5,658	6,481
2018	Feb	5,909	8,299	4,559	6,398
2018	Mar	1,399	1,736	1,088	1,461
2018	Apr	1,479	1,608	1,240	1,388
2018	May	1,345	1,426	1,148	1,221
2018	Jun	1,411	1,563	1,236	1,350
2018	Jul	1,727	2,159	1,457	1,796
2018	Aug	1,816	2,124	1,463	1,703
2018	Sep	1,424	1,559	1,208	1,326
2018	Oct	1,838	2,118	1,610	1,954
2018	Nov	1,539	1,922	1,371	1,689
2018	Dec	1,606	1,787	1,426	1,608
2018	Annual	2,456	2,899	1,955	2,365

Table 3-57 and Figure 3-45 show total cleared up to congestion transactions by type in 2017 and 2018. Total up to congestion transactions in 2017 decreased by 49.5 percent from 306.0 million MW in 2017 to 154.4 million MW in 2018. Internal up to congestion transactions in 2018 were 65.8 percent of all up to congestion transactions compared to 85.4 percent in 2017.

Table 3-57 Cleared up to congestion transactions by type (MW): 2017 and 2018

	2017				
	Cleared Up to Congestion Bids				
	Import	Export	Wheel	Internal	Total
Top ten total (MW)	4,518,009	5,707,881	1,379,663	14,533,132	26,138,685
PJM total (MW)	22,394,654	20,710,413	1,652,065	261,207,130	305,964,262
Top ten total as percent of PJM total	20.2%	27.6%	83.5%	5.6%	8.5%
PJM total as percent of all up to congestion transactions	7.3%	6.8%	0.5%	85.4%	100.0%
	2018				
	Cleared Up to Congestion Bids				
	Import	Export	Wheel	Internal	Total
Top ten total (MW)	13,529,647	4,505,049	4,764,846	11,005,677	33,805,219
PJM total (MW)	32,994,068	13,250,859	6,608,284	101,534,802	154,388,013
Top ten total as percent of PJM total	41.0%	34.0%	72.1%	10.8%	21.9%
PJM total as percent of all up to congestion transactions	21.4%	8.6%	4.3%	65.8%	100.0%

Figure 3-45 shows the initial increase and continued increase in internal up to congestion transactions by month following the November 1, 2012 rule change permitting such transactions, until September 8, 2014. The reduction in up to congestion transactions (UTC) that followed a FERC order setting September 8, 2014, as the effective date for any uplift charges subsequently assigned to UTCs, was reversed. There was an increase in up to congestion volume as a result of the expiration of the 15 month refund period for the proceeding related to uplift charges for UTC transactions.[97] But in 2018, the percent of marginal up to congestion transactions again decreased significantly as the result of a FERC order issued on February 20, 2018 and implemented on February 22, 2018.[98] The order limited UTC trading to hubs, residual metered load, and interfaces. The reduction in UTC bid locations effective February 22, 2018, resulted in a significant reduction in total activity.

Figure 3-45 Monthly cleared up to congestion transactions by type (MW): January 2005 through December 2018

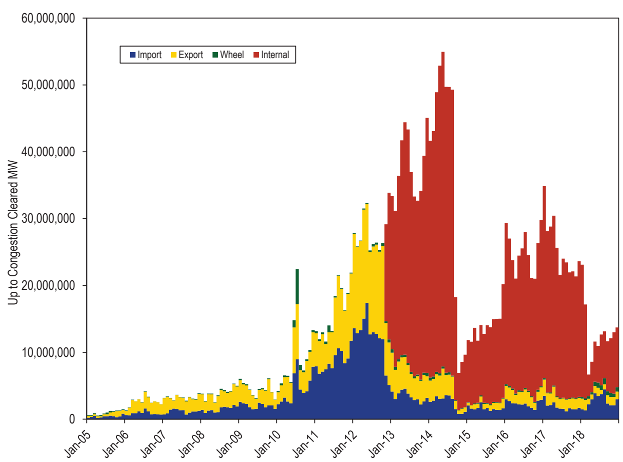
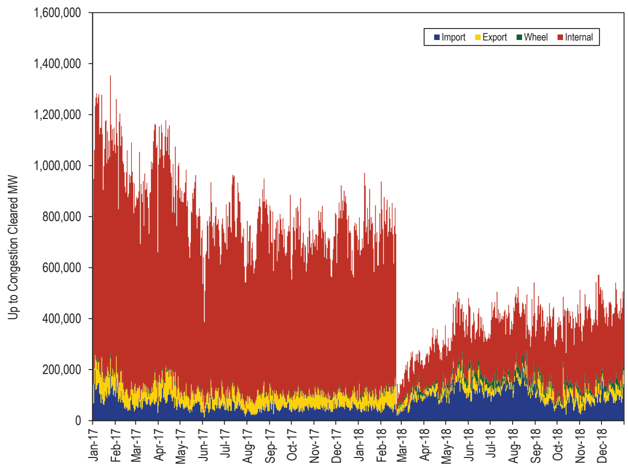


Figure 3-46 shows the daily cleared up to congestion MW by transaction type from January 1, 2017 through December 31, 2018.

97 *Id.*
98 162 FERC ¶ 61,139 (2018).

Figure 3-46 Daily cleared up to congestion transaction by type (MW): January 2017 through December 2018



Market Performance

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

Markup

The markup index is a measure of the competitiveness of participant behavior for individual units. The markup in dollars is a measure of the impact of participant behavior on the generator bus market price when a unit is marginal. As an example, if unit A has a $90 cost and a $100 price, while unit B has a $9 cost and a $10 price, both would show a markup index of 10 percent, but the price impact of unit A's markup at the generator bus would be $10 while the price impact of unit B's markup at the generator bus would be $1. Depending on each unit's location on the transmission system, those bus level impacts could also have different impacts on total system price. Markup can also affect prices when units with markups are not marginal by altering the economic dispatch order of supply.

The MMU calculates an explicit measure of the impact of marginal unit incremental energy offer markups on LMP using the mathematical relationships among LMPs in the market solution.[99] The markup impact calculation sums, over all marginal units, the product of the dollar markup of the unit and the marginal impact of the unit's offer on the system load-weighted LMP. The markup impact includes the impact of the identified markup behavior of all marginal units. Positive and negative markup impacts may offset one another. The markup analysis is a direct measure of market performance. It does not take into account whether or not marginal units have either locational or aggregate structural market power.

The markup calculation is not based on a counterfactual redispatch of the system to determine the marginal units and their marginal costs that would have occurred if all units had made all offers at short run marginal cost. A full redispatch analysis is practically impossible and a limited redispatch analysis would not be dispositive. Nonetheless, such a hypothetical counterfactual analysis would reveal the extent to which the actual system dispatch is less than competitive if it showed a difference between dispatch based on short run marginal cost and actual dispatch. It is possible that the unit-specific markup, based on a redispatch analysis, would be lower than the markup component of price if the reference point were an inframarginal unit with a lower price and a higher cost than the actual marginal unit. If the actual marginal unit has short run marginal costs that would cause it to be inframarginal, a new unit would be marginal. If the offer of that new unit were greater than the cost of the original marginal unit, the markup impact would be lower than the MMU measure. If the newly marginal unit is on a price-based schedule, the analysis would have to capture the markup impact of that unit as well.

Real-Time Markup

Markup Component of Real-Time Price by Fuel, Unit Type

The markup component of price is the difference between the system price, when the system price is determined by

99 The MMU calculates the impact on system prices of marginal unit price-cost markup, based on analysis using sensitivity factors. The calculation shows the markup component of LMP based on a comparison between the price-based incremental energy offer and the cost-based incremental energy offer of each actual marginal unit on the system. This is the same method used to calculate the fuel cost adjusted LMP and the components of LMP. The markup analysis does not include markup in start up or no load offers. *See* Calculation and Use of Generator Sensitivity/Unit Participation Factors, 2010 State of the Market Report for PJM: Technical Reference for PJM Markets.

the active offers of the marginal units, whether price or cost-based, and the system price, based on the cost-based offers of those marginal units.

Table 3-58 shows the impact (markup component of LMP) of the marginal unit markup behavior by fuel type and unit type on the real-time load-weighted average system LMP, using unadjusted and adjusted offers. The adjusted markup component of LMP increased from $4.94 per MWh in 2017 to $7.27 per MWh in 2018. The adjusted markup contribution of coal units in 2018 was $2.15 per MWh. The adjusted markup component of gas fired units in 2018 was $4.56 per MWh, an increase of $1.21 per MWh from 2017. The markup component of wind units was $0.00 per MWh. If a price-based offer is negative, but less negative than a cost-based offer, the markup is positive. In 2018, among the wind units that were marginal, 70.8 percent had negative offer prices.

Table 3-58 Markup component of real-time, load-weighted, average LMP by primary fuel type and unit type: 2017 and 2018[100]

		2017		2018	
Fuel Type	Unit Type	Markup Component of LMP (Unadjusted)	Markup Component of LMP (Adjusted)	Markup Component of LMP (Unadjusted)	Markup Component of LMP (Adjusted)
Coal	Steam	$0.35	$1.38	$1.31	$2.15
Gas	CC	$1.80	$2.86	$2.58	$3.90
Gas	CT	$0.22	$0.40	$0.27	$0.56
Gas	RICE	($0.00)	$0.01	$0.00	$0.01
Gas	Steam	$0.02	$0.09	$0.02	$0.09
Municipal Waste	CT	$0.00	$0.00	$0.00	$0.00
Municipal Waste	RICE	$0.00	$0.00	$0.00	$0.00
Municipal Waste	Steam	$0.00	$0.00	$0.00	$0.00
Oil	CC	($0.00)	$0.00	$0.15	$0.17
Oil	CT	$0.01	$0.04	$0.06	$0.18
Oil	RICE	$0.00	$0.00	$0.00	$0.00
Oil	Steam	($0.01)	$0.00	$0.10	$0.13
Other		$0.09	$0.09	$0.07	$0.07
Uranium		$0.00	$0.00	($0.00)	($0.00)
Wind		$0.07	$0.07	$0.00	$0.00
Total		$2.55	$4.94	$4.56	$7.27

Markup Component of Real-Time Price

Table 3-59 shows the markup component, calculated using unadjusted offers, of average prices and of average monthly on peak and off peak prices. Table 3-60 shows the markup component, calculated using adjusted offers, of average prices and of average monthly on peak and off peak prices. In 2018, when using unadjusted cost-based offers, $4.56 per MWh of the PJM real-time load-weighted average LMP was attributable to markup. Using adjusted cost-based offers, $7.27 per MWh of the PJM real-time load-weighted, average LMP was attributable to markup. In 2018, the off peak markup component was highest in January, $11.65 per MWh using unadjusted cost-based offers and $17.60 per MWh using adjusted cost-based offers. This corresponds to 13.28 percent and 20.07 percent of the real-time off peak load-weighted average LMP in January.

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

Table 3-59 Monthly markup components of real-time load-weighted LMP (Unadjusted): 2017 and 2018

	2017			2018		
	Markup Component (All Hours)	Off Peak Markup Component	Peak Markup Component	Markup Component (All Hours)	Off Peak Markup Component	Peak Markup Component
Jan	$1.75	$0.47	$3.11	$9.29	$11.65	$6.89
Feb	$1.47	$0.53	$2.36	$1.47	$0.95	$1.97
Mar	$1.10	$1.70	$0.55	$4.94	$2.68	$7.15
Apr	$1.87	$0.93	$2.86	$5.71	$3.47	$7.92
May	$2.91	($0.01)	$5.51	$5.20	$1.57	$8.45
Jun	$3.08	$0.93	$4.88	$2.86	$1.96	$3.69
Jul	$3.62	$2.16	$5.12	$4.84	$1.50	$8.01
Aug	$2.87	$1.51	$3.94	$4.81	$1.94	$7.12
Sep	$3.42	$1.46	$5.35	$6.55	$3.71	$9.63
Oct	$2.52	$1.33	$3.62	$3.93	$2.28	$5.32
Nov	$0.72	$0.68	$0.77	$2.70	$1.21	$4.16
Dec	$4.68	$5.03	$4.26	$1.45	$0.91	$2.07
Total	$2.55	$1.49	$3.58	$4.56	$2.95	$6.10

Table 3-60 Monthly markup components of real-time load-weighted LMP (Adjusted): 2017 and 2018

	2017			2018		
	Markup Component (All Hours)	Off Peak Markup Component	Peak Markup Component	Markup Component (All Hours)	Off Peak Markup Component	Peak Markup Component
Jan	$4.43	$3.07	$5.88	$14.99	$17.60	$12.33
Feb	$3.66	$2.60	$4.67	$3.64	$2.96	$4.32
Mar	$3.56	$3.82	$3.33	$7.28	$4.89	$9.63
Apr	$4.01	$2.95	$5.12	$8.16	$5.73	$10.56
May	$5.33	$2.07	$8.23	$7.38	$3.48	$10.86
Jun	$5.29	$2.85	$7.33	$4.94	$3.87	$5.95
Jul	$6.08	$4.29	$7.92	$7.21	$3.61	$10.62
Aug	$5.06	$3.43	$6.35	$7.24	$4.16	$9.71
Sep	$5.57	$3.37	$7.73	$8.92	$5.85	$12.25
Oct	$4.77	$3.34	$6.08	$6.36	$4.48	$7.94
Nov	$3.16	$2.88	$3.43	$5.57	$3.88	$7.24
Dec	$7.64	$7.85	$7.40	$4.14	$3.47	$4.92
Total	$4.94	$3.66	$6.18	$7.27	$5.52	$8.96

Hourly Markup Component of Real-Time Prices

Figure 3-47 shows the markup contribution to the hourly load-weighted LMP using unadjusted cost offers in 2018 and 2017. Figure 3-48 shows the markup contribution to the hourly load-weighted LMP using adjusted cost-based offers in 2018 and 2017. The hourly markup component of real-time prices was higher during the first eight days of January 2018, when the PJM region experienced particularly low temperatures.

Figure 3-47 Markup contribution to real-time hourly load-weighted LMP (Unadjusted): 2017 and 2018

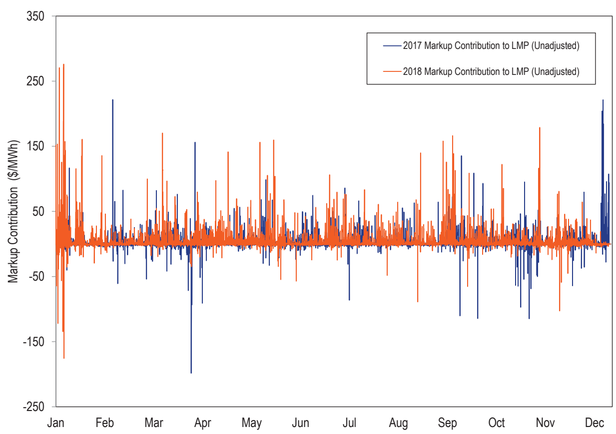
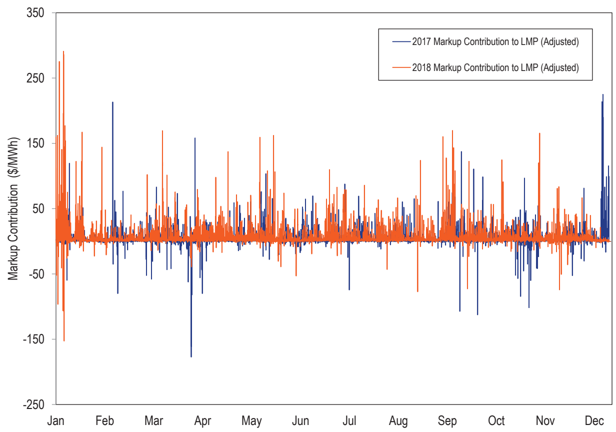


Figure 3-48 Markup contribution to real-time hourly load-weighted LMP (Adjusted): 2017 and 2018



Markup Component of Real-Time Zonal Prices

The unit markup component of average real-time price using unadjusted offers is shown for each zone in 2017 and 2018 in Table 3-61 and for adjusted offers in Table 3-62. The smallest zonal all hours average markup component using unadjusted offers in 2018, excluding the OVEC Zone, was in the ComEd Control Zone, 3.24 per MWh, while the highest was in the BGE Control Zone, $5.98 per MWh. The smallest zonal on peak average markup component using unadjusted offers in 2018, excluding the OVEC Zone, was in the PSEG Control Zone, 4.79 per MWh, while the highest was in the BGE Control Zone, $8.29 per MWh.

Table 3-61 Average real-time zonal markup component (Unadjusted): 2017 and 2018

	2017			2018		
	Markup Component (All Hours)	Off Peak Markup Component	Peak Markup Component	Markup Component (All Hours)	Off Peak Markup Component	Peak Markup Component
AECO	$2.38	$1.67	$3.09	$4.29	$3.02	$5.53
AEP	$2.25	$1.27	$3.20	$4.37	$2.91	$5.80
APS	$2.56	$1.47	$3.65	$4.83	$3.18	$6.47
ATSI	$2.36	$1.23	$3.43	$5.36	$3.20	$7.42
BGE	$3.46	$2.16	$4.73	$5.98	$3.61	$8.29
ComEd	$2.17	$1.08	$3.19	$3.24	$1.38	$4.99
DAY	$2.33	$1.30	$3.30	$4.74	$3.06	$6.31
DEOK	$2.39	$1.29	$3.46	$4.90	$3.31	$6.45
DLCO	$2.32	$1.16	$3.44	$5.53	$3.38	$7.60
DPL	$2.76	$2.02	$3.48	$4.34	$2.92	$5.72
Dominion	$3.18	$1.88	$4.47	$5.58	$4.07	$7.07
EKPC	$2.08	$1.27	$2.92	$4.32	$3.19	$5.48
JCPL	$2.77	$1.77	$3.70	$4.07	$2.97	$5.07
Met-Ed	$2.37	$1.44	$3.26	$4.17	$2.83	$5.42
OVEC	NA	NA	NA	$1.30	$0.84	$2.04
PECO	$2.26	$1.58	$2.90	$3.99	$2.58	$5.32
PENELEC	$2.60	$1.49	$3.65	$4.51	$2.89	$6.04
PPL	$2.37	$1.46	$3.23	$3.81	$2.39	$5.15
PSEG	$2.82	$1.69	$3.88	$3.80	$2.75	$4.79
Pepco	$3.13	$1.90	$4.30	$5.36	$3.50	$7.11
RECO	$3.07	$2.03	$3.97	$4.11	$2.71	$5.33

Table 3-62 Average real-time zonal markup component (Adjusted): 2017 and 2018

	2017			2018		
	Markup Component (All Hours)	Off Peak Markup Component	Peak Markup Component	Markup Component (All Hours)	Off Peak Markup Component	Peak Markup Component
AECO	$4.74	$3.80	$5.67	$6.80	$5.47	$8.09
AEP	$4.59	$3.43	$5.73	$7.03	$5.42	$8.62
APS	$4.98	$3.68	$6.26	$7.69	$5.89	$9.46
ATSI	$4.82	$3.43	$6.15	$8.12	$5.71	$10.41
BGE	$6.05	$4.46	$7.60	$9.08	$6.53	$11.55
ComEd	$4.37	$3.06	$5.60	$5.55	$3.57	$7.42
DAY	$4.75	$3.50	$5.92	$7.45	$5.53	$9.25
DEOK	$4.68	$3.40	$5.92	$7.50	$5.71	$9.24
DLCO	$4.72	$3.33	$6.06	$8.27	$5.86	$10.59
DPL	$5.36	$4.49	$6.22	$7.37	$5.68	$9.01
Dominion	$5.67	$4.17	$7.16	$8.61	$7.05	$10.14
EKPC	$4.39	$3.40	$5.40	$6.89	$5.59	$8.22
JCPL	$5.16	$3.92	$6.30	$6.72	$5.49	$7.83
Met-Ed	$4.80	$3.55	$5.99	$6.77	$5.28	$8.16
OVEC	NA	NA	NA	$3.83	$3.29	$4.72
PECO	$4.60	$3.73	$5.43	$6.63	$5.08	$8.10
PENELEC	$5.03	$3.64	$6.35	$7.22	$5.38	$8.96
PPL	$4.74	$3.62	$5.81	$6.39	$4.89	$7.81
PSEG	$5.20	$3.82	$6.50	$6.40	$5.23	$7.49
Pepco	$5.65	$4.16	$7.06	$8.42	$6.44	$10.30
RECO	$5.48	$4.16	$6.63	$6.69	$5.13	$8.03

Markup by Real Time Price Levels

Table 3-63 shows the markup contribution to the LMP, based on the unadjusted cost-based offers and adjusted cost-based offers of the marginal units, when the PJM system wide load weighted average LMP was in the identified price range.

Table 3-63 Real-time markup contribution (By PJM load weighted LMP category, unadjusted): 2017 and 2018

	2017		2018	
LMP Category	Markup Component	Frequency	Markup Component	Frequency
< $25	($0.16)	47.9%	($0.36)	36.2%
$25 to $50	$2.38	45.9%	$2.98	52.7%
$50 to $75	$14.70	4.2%	$17.65	6.3%
$75 to $100	$20.73	1.2%	$23.28	1.9%
$100 to $125	$27.87	0.4%	$30.09	1.2%
$125 to $150	$24.81	0.2%	$21.30	0.5%
>= $150	$79.39	0.2%	$44.40	1.3%

Table 3-64 Real-time markup contribution (By PJM load weighted LMP category, adjusted): 2017 and 2018

	2017		2018	
LMP Category	Markup Component	Frequency	Markup Component	Frequency
< $25	$1.77	47.9%	$1.60	36.2%
$25 to $50	$4.99	45.9%	$5.63	52.7%
$50 to $75	$18.19	4.2%	$20.93	6.3%
$75 to $100	$25.70	1.2%	$27.91	1.9%
$100 to $125	$33.94	0.4%	$36.36	1.2%
$125 to $150	$31.07	0.2%	$29.77	0.5%
>= $150	$81.86	0.2%	$56.70	1.3%

Markup by Company

Table 3-65 shows the markup contribution based on the unadjusted cost-based offers and adjusted cost-based offers to real-time, load-weighted average LMP by individual marginal resource owners. The markup contribution of each marginal resource to price at each load bus is calculated for each five-minute interval, and summed by the parent company that offers the marginal resource into the Real-Time Energy Market. In 2018, when using unadjusted cost based offers, the markup of one company accounted for 2.8 percent of the load weighted average LMP, the markup of the top five companies accounted for 8.4 percent of the load weighted average LMP and the markup of all companies accounted for 11.9 percent of the load weighted average LMP. In 2017, when using unadjusted cost-based offers, the markup of one company accounted for 2.2 percent of the load weighted average LMP, the markup of the top five companies accounted for 6.5 percent of the load weighted average LMP and the markup of all companies accounted for 8.2 percent of the load weighted average LMP. The top five companies' markup contribution to the load weighted average LMP and the dollar values of their markup increased in 2018. The markup contribution to the load weighted average LMP and share of the markup contribution to the load weighted average LMP also increased in 2018.

Table 3-65 Markup component of real-time, load-weighted, average LMP by Company: 2017 and 2018[101]

	2017				2018			
	Markup Component of LMP (Unadjusted)		Markup Component of LMP (Adjusted)		Markup Component of LMP (Unadjusted)		Markup Component of LMP (Adjusted)	
	$/MWh	Percent of Load Weighted LMP	$/MWh	Percent of Load Weighted LMP	$/MWh	Percent of Load Weighted LMP	$/MWh	Percent of Load Weighted LMP
Top 1 Company	$0.68	2.2%	$1.02	3.3%	$1.05	2.8%	$1.41	3.7%
Top 2 Companies	$1.13	3.6%	$1.75	5.7%	$1.76	4.6%	$2.32	6.1%
Top 3 Companies	$1.53	4.9%	$2.40	7.7%	$2.42	6.3%	$3.05	8.0%
Top 4 Companies	$1.85	6.0%	$2.79	9.0%	$2.90	7.6%	$3.71	9.7%
Top 5 Companies	$2.02	6.5%	$3.15	10.2%	$3.23	8.4%	$4.11	10.8%
All Companies	$2.55	8.2%	$4.94	16.0%	$4.56	11.9%	$7.27	19.0%

Day-Ahead Markup

Markup Component of Day-Ahead Price by Fuel, Unit Type

The markup component of the PJM day-ahead, load-weighted average LMP by primary fuel and unit type is shown in Table 3-66. INC, DEC and up to congestion transactions (UTC) have zero markups. INCs were 9.8 percent of marginal resources and DECs were 16.9 percent of marginal resources in 2018. The share of marginal up to congestion transactions decreased significantly beginning on September 8, 2014, as a result of the FERC's UTC uplift refund notice which became effective on September 8, 2014. However, the share of marginal up to congestion transactions increased from 76.1 percent in 2015 to 82.4 percent in 2016 due to the expiration of the 15 months resettlement period for the proceeding related to uplift charges for UTC transactions. The share of marginal up to congestion transactions decreased from 79.9 percent in 2017 to 62.3 percent in 2018 as the result of a FERC order issued on February 20, 2018, and implemented on February 22, 2018.[102] The order limited UTC trading to hubs, residual metered load, and interfaces.

The adjusted markup of coal, gas and oil units is calculated as the difference between the price-based offer, and the cost-based offer excluding the 10 percent adder. Table 3-66 shows the markup component of LMP for marginal generating resources. Generating resources were only 10.9 percent of marginal resources in 2018. Using adjusted cost-based offers, the markup component of LMP for marginal generating resources increased for coal fired steam units from $0.95 to $1.38 and increased for gas fired CT units from $0.08 to $0.11. The markup component of LMP for coal fired steam units increased from $0.22 in 2017 to $0.69 in 2018 using unadjusted cost-based offers

Table 3-66 Markup component of day-ahead, load-weighted, average LMP by primary fuel type and unit type: 2017 and 2018

		2017			2018		
Fuel Type	Unit Type	Markup Component of LMP (Unadjusted)	Markup Component of LMP (Adjusted)	Frequency	Markup Component of LMP (Unadjusted)	Markup Component of LMP (Adjusted)	Frequency
Coal	Steam	$0.22	$0.95	42.8%	$0.69	$1.38	43.6%
Gas	CT	$0.04	$0.08	2.7%	$0.04	$0.11	3.4%
Gas	RICE	$0.00	$0.00	0.5%	$0.00	$0.00	0.6%
Gas	Steam	$0.45	$1.00	40.2%	$0.49	$1.18	47.7%
Oil	CT	($0.00)	$0.00	7.0%	$0.00	$0.00	0.5%
Oil	RICE	$0.00	($0.00)	0.3%	$0.00	$0.00	0.0%
Oil	Steam	($0.01)	($0.01)	0.0%	($0.01)	$0.08	0.6%
Other	Solar	$0.00	$0.00	0.0%	$0.00	$0.00	0.3%
Other	Steam	$0.01	$0.01	0.1%	($0.00)	($0.00)	0.1%
Uranium	Steam	$0.00	$0.00	2.3%	$0.00	$0.00	1.5%
Water	Hydro	$0.00	$0.00	0.2%	$0.00	$0.00	0.0%
Wind	Wind	$0.01	$0.01	3.9%	$0.01	$0.01	1.6%
Total		$0.72	$2.04	100.0%	$1.22	$2.76	100.0%

Markup Component of Day-Ahead Price

The markup component of price is the difference between the system price, when the system price is determined by the active offers of the marginal units, whether price or cost-based, and the system price, based on the cost-based offers of those marginal units. Only hours when

101 The Unit Type Diesel refers to power generation using reciprocating internal combustion engines. Such Diesel units can use a variety of fuel types including diesel, natural gas, oil and gas from municipal waste.

102 162 FERC ¶ 61,139 (2018).

generating units were marginal on either priced-based offers or on cost-based offers were included in the markup calculation.

Table 3-67 shows the markup component of average prices and of average monthly on-peak and off-peak prices using unadjusted cost-based offers. In 2018, when using unadjusted cost-based offers, $1.22 per MWh of the PJM day-ahead load-weighted average LMP was attributable to markup. In 2018, the peak markup component was highest in January, $4.21 per MWh using unadjusted cost-based offers.

Table 3-67 Monthly markup components of day-ahead (Unadjusted), load-weighted LMP: 2017 and 2018

	2017			2018		
	Markup Component (All Hours)	Peak Markup Component	Off Peak Markup Component	Markup Component (All Hours)	Peak Markup Component	Off Peak Markup Component
Jan	($0.03)	$0.19	($0.23)	$3.15	$4.21	$2.08
Feb	$0.25	$0.59	($0.10)	$0.87	$1.65	$0.05
Mar	$0.38	$0.83	($0.12)	$0.46	$0.61	$0.31
Apr	$0.82	$1.64	$0.03	$1.09	$1.55	$0.62
May	$0.45	$1.07	($0.25)	$0.83	$1.22	$0.40
Jun	$0.90	$1.35	$0.35	$0.29	$0.67	($0.13)
Jul	$0.60	$1.12	$0.09	$1.39	$2.50	$0.20
Aug	$1.13	$1.94	$0.09	$1.03	$1.76	$0.11
Sep	$1.65	$2.72	$0.57	$1.96	$3.14	$0.85
Oct	$1.71	$2.69	$0.64	$1.21	$1.56	$0.80
Nov	($0.08)	($0.23)	$0.08	$1.26	$1.98	$0.53
Dec	$0.90	$1.60	$0.29	$0.81	$1.37	$0.33
Annual	$0.72	$1.29	$0.12	$1.22	$1.88	$0.53

Table 3-68 shows the markup component of average prices and of average monthly on peak and off peak prices using adjusted cost-based offers. In 2018, when using adjusted cost-based offers, $2.76 per MWh of the PJM day-ahead load-weighted average LMP was attributable to markup. In 2018, the peak markup component was highest in January, $7.41 per MWh using adjusted cost-based offers.

Table 3-68 Monthly markup components of day-ahead (Adjusted), load-weighted LMP: 2017 and 2018

	2017			2018		
	Markup Component (All Hours)	Peak Markup Component	Off Peak Markup Component	Markup Component (All Hours)	Peak Markup Component	Off Peak Markup Component
Jan	$1.40	$1.49	$1.32	$6.31	$7.41	$5.21
Feb	$1.65	$1.89	$1.39	$2.46	$3.32	$1.57
Mar	$1.65	$1.99	$1.27	$1.78	$1.89	$1.67
Apr	$1.94	$2.50	$1.41	$2.17	$2.51	$1.82
May	$1.62	$2.05	$1.14	$2.00	$2.25	$1.72
Jun	$2.40	$2.96	$1.71	$1.75	$2.01	$1.47
Jul	$1.73	$1.96	$1.50	$2.73	$3.70	$1.70
Aug	$2.40	$3.09	$1.52	$2.36	$2.88	$1.71
Sep	$2.98	$3.99	$1.96	$3.16	$4.17	$2.22
Oct	$2.88	$3.76	$1.92	$2.44	$2.66	$2.17
Nov	$1.33	$1.13	$1.53	$2.75	$3.21	$2.28
Dec	$2.52	$3.10	$2.03	$2.69	$3.24	$2.20
Annual	$2.04	$2.50	$1.56	$2.76	$3.31	$2.19

Markup Component of Day-Ahead Zonal Prices

The markup component of annual average day-ahead price using unadjusted cost-based offers is shown for each zone in Table 3-69. The markup component of annual average day-ahead price using adjusted cost-based offers is shown for each zone in Table 3-70. The smallest zonal all hours average markup component using adjusted cost-based offers for 2018 was in the ComEd Zone, $2.39 per MWh, while the highest was in the AECO Control Zone, $3.29 per MWh. The smallest zonal on peak average markup using adjusted cost-based offers was in the DLCO Control Zone, $2.92 per MWh, while the highest was in the AECO Control Zone, $3.95 per MWh.

Table 3-69 Day-ahead, average, zonal markup component (Unadjusted): 2017 and 2018

	2017			2018		
	Markup Component (All Hours)	Peak Markup Component	Off Peak Markup Component	Markup Component (All Hours)	Peak Markup Component	Off Peak Markup Component
AECO	$1.06	$1.70	$0.38	$1.65	$2.40	$0.84
AEP	$0.72	$1.34	$0.09	$1.15	$1.79	$0.49
APS	$0.64	$1.22	$0.05	$1.14	$1.75	$0.50
ATSI	$0.72	$1.28	$0.12	$1.16	$1.74	$0.54
BGE	$0.58	$1.15	($0.01)	$0.97	$1.54	$0.36
ComEd	$0.49	$0.93	$0.02	$1.00	$1.65	$0.30
DAY	$0.78	$1.41	$0.10	$1.23	$1.84	$0.58
DEOK	$0.82	$1.51	$0.10	$1.47	$2.36	$0.54
DLCO	$0.72	$1.27	$0.13	$1.13	$1.67	$0.55
Dominion	$0.67	$1.33	($0.00)	$1.02	$1.63	$0.40
DPL	$0.85	$1.36	$0.33	$1.44	$2.09	$0.77
EKPC	$0.69	$1.25	$0.15	$1.40	$2.30	$0.52
JCPL	$0.95	$1.48	$0.36	$1.59	$2.27	$0.83
Met-Ed	$0.99	$1.69	$0.23	$1.51	$2.18	$0.79
OVEC	NA	NA	NA	$0.00	$0.00	$0.00
PECO	$0.92	$1.47	$0.33	$1.64	$2.41	$0.82
PENELEC	$0.68	$1.24	$0.11	$1.26	$1.97	$0.48
Pepco	$0.63	$1.25	($0.02)	$0.93	$1.49	$0.33
PPL	$0.87	$1.45	$0.26	$1.56	$2.29	$0.80
PSEG	$0.94	$1.51	$0.32	$1.54	$2.19	$0.82

Table 3-70 Day-ahead, average, zonal markup component (Adjusted): 2017 and 2018

	2017			2018		
	Markup Component (All Hours)	Peak Markup Component	Off Peak Markup Component	Markup Component (All Hours)	Peak Markup Component	Off Peak Markup Component
AECO	$2.39	$2.92	$1.84	$3.29	$3.95	$2.58
AEP	$2.06	$2.56	$1.54	$2.64	$3.15	$2.11
APS	$1.98	$2.43	$1.51	$2.68	$3.14	$2.20
ATSI	$2.07	$2.52	$1.58	$2.64	$3.08	$2.17
BGE	$1.96	$2.41	$1.49	$2.63	$3.09	$2.15
ComEd	$1.75	$2.08	$1.40	$2.39	$2.99	$1.76
DAY	$2.14	$2.67	$1.58	$2.75	$3.22	$2.23
DEOK	$2.13	$2.69	$1.53	$2.92	$3.71	$2.09
DLCO	$2.02	$2.46	$1.56	$2.55	$2.92	$2.17
Dominion	$2.03	$2.56	$1.48	$2.66	$3.16	$2.16
DPL	$2.22	$2.58	$1.84	$3.06	$3.57	$2.52
EKPC	$2.01	$2.43	$1.58	$2.93	$3.76	$2.12
JCPL	$2.26	$2.67	$1.82	$3.24	$3.84	$2.58
Met-Ed	$2.31	$2.90	$1.66	$3.11	$3.68	$2.48
OVEC	NA	NA	NA	$0.00	$0.00	$0.00
PECO	$2.24	$2.67	$1.80	$3.29	$3.95	$2.58
PENELEC	$1.97	$2.41	$1.51	$2.75	$3.36	$2.08
Pepco	$2.00	$2.51	$1.47	$2.57	$3.01	$2.10
PPL	$2.19	$2.63	$1.72	$3.18	$3.80	$2.53
PSEG	$2.23	$2.66	$1.76	$3.17	$3.72	$2.56

Markup by Day-Ahead Price Levels

Table 3-71 and Table 3-72 show the average markup component of LMP, based on the unadjusted cost-based offers and adjusted cost-based offers of the marginal units, when the PJM system LMP was in the identified price range.

Table 3-71 Average, day-ahead markup component (By LMP category, unadjusted): 2017 and 2018

	2017		2018	
LMP Category	Average Markup Component	Frequency	Average Markup Component	Frequency
< $25	($0.10)	43.4%	($0.11)	29.0%
$25 to $50	$0.56	52.7%	$0.81	60.6%
$50 to $75	$0.18	2.9%	$0.21	6.1%
$75 to $100	$0.05	0.7%	$0.07	1.8%
$100 to $125	$0.01	0.2%	$0.06	0.9%
$125 to $150	$0.01	0.0%	$0.04	0.6%
>= $150	$0.02	0.1%	$0.13	0.9%

Table 3-72 Average, day-ahead markup component (By LMP category, adjusted): 2017 and 2018

	2017		2018	
LMP Category	Average Markup Component	Frequency	Average Markup Component	Frequency
< $25	$0.43	43.4%	$0.26	29.0%
$25 to $50	$1.27	52.7%	$1.71	60.6%
$50 to $75	$0.24	2.9%	$0.29	6.1%
$75 to $100	$0.06	0.7%	$0.12	1.8%
$100 to $125	$0.02	0.2%	$0.10	0.9%
$125 to $150	$0.01	0.0%	$0.07	0.6%
>= $150	$0.02	0.1%	$0.21	0.9%

Prices

The behavior of individual market entities within a market structure is reflected in market prices. PJM locational marginal prices (LMPs) are a direct measure of market performance. Price level is a good, general indicator of market performance, although overall price results must be interpreted carefully because of the multiple factors that affect them. Among other things, overall average prices reflect changes in supply and demand, generation fuel mix, the cost of fuel, emission related expenses, markup and local price differences caused by congestion. PJM also may administratively set prices with the creation of a closed loop interface related to demand side resources or reactive power.

Real-time and day-ahead energy market load-weighted prices were 23.4 percent and 23.1 percent higher in 2018 than in 2017.

PJM real-time energy market prices increased in 2018 compared to 2017. The average LMP was 21.5 percent higher in 2018 than in 2017, $35.75 per MWh versus $29.42 per MWh. The load-weighted average real-time LMP was 23.4 percent higher in 2018 than in 2017, $38.24 per MWh versus $30.99 per MWh.

The real-time load-weighted average LMP for 2018 was 7.2 percent higher than the real-time fuel-cost adjusted, load-weighted, average LMP for 2018. If fuel and emission costs in 2018 had been the same as in 2017, holding everything else constant, the load-weighted LMP would have been lower, $35.68 per MWh instead of the observed $38.24 per MWh.

PJM day-ahead energy market prices increased in 2018 compared to 2017. The day-ahead average LMP was 21.1 percent higher in 2018 than in 2017, $35.69 per MWh versus $29.48 per MWh. The day-ahead load-weighted average LMP was 23.1 percent higher in 2018 than in 2017, $37.97 per MWh versus $30.85 per MWh.

Occasionally, in a constrained market, the LMPs at some pricing nodes can exceed the offer price of the highest cleared generator in the supply stack.[103] In the nodal pricing system, the LMP at a pricing node is the total cost of meeting incremental demand at that node. When there are binding transmission constraints, satisfying the marginal increase in demand at a node may require increasing the output of some generators while simultaneously decreasing the output of other generators, such that the transmission constraints are not violated. The total cost of redispatching multiple generators can at times exceed the cost of marginally increasing the output of the most expensive generator offered. Thus, the LMPs at some pricing nodes exceed $1,000 per MWh, the cap on the generators' offer price in the PJM market.[104]

Real-Time LMP

Real-time average LMP is the hourly average LMP for the PJM Real-Time Energy Market.[105]

103 See O'Neill R. P, Mead D. and Malvadkar P. "On Market Clearing Prices Higher than the Highest Bid and Other Almost Paranormal Phenomena." *The Electricity Journal* 2005; 18(2) at 19–27.

104 The offer cap in PJM was temporarily increased to $1,800 per MWh prior to the winter of 2014/2015. A new cap of $2,000 per MWh, only for offers with costs exceeding $1,000 per MWh, went into effect on December 14, 2015. See 153 FERC ¶ 61,289 (2015).

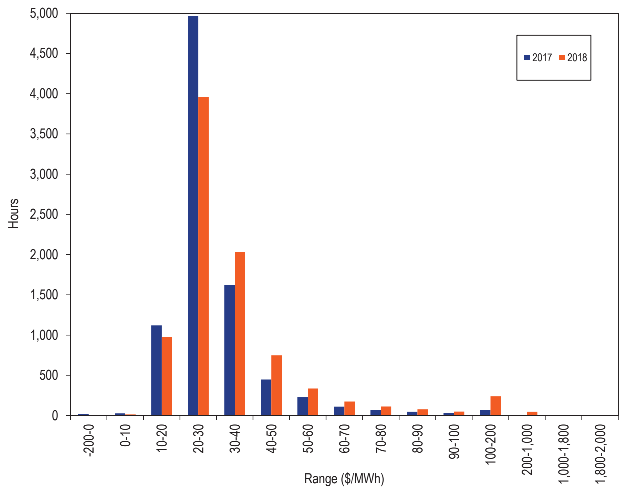
105 See the 2010 State of the Market Report for PJM: *Technical Reference for PJM Markets*, at "Calculating Locational Marginal Price," p 16-18 for detailed definition of Real-Time LMP. <http://www.monitoringanalytics.com/reports/Technical_References/references.shtml>.

Real-Time Average LMP

PJM Real-Time Average LMP Duration

Figure 3-49 shows the hourly distribution of PJM real-time average LMP for 2017 and 2018.

Figure 3-49 Average LMP for the Real-Time Energy Market: 2017 and 2018



PJM Real-Time, Average LMP

Table 3-73 shows the PJM real-time, average LMP for 1998 through 2018.[106]

Table 3-73 Real-time, average LMP (Dollars per MWh): 1998 through 2018

	Real-Time LMP			Year-to-Year Change		
	Average	Median	Standard Deviation	Average	Median	Standard Deviation
1998	$21.72	$16.60	$31.45	NA	NA	NA
1999	$28.32	$17.88	$72.42	30.4%	7.7%	130.3%
2000	$28.14	$19.11	$25.69	(0.6%)	6.9%	(64.5%)
2001	$32.38	$22.98	$45.03	15.1%	20.3%	75.3%
2002	$28.30	$21.08	$22.41	(12.6%)	(8.3%)	(50.2%)
2003	$38.28	$30.79	$24.71	35.3%	46.1%	10.3%
2004	$42.40	$38.30	$21.12	10.8%	24.4%	(14.5%)
2005	$58.08	$47.18	$35.91	37.0%	23.2%	70.0%
2006	$49.27	$41.45	$32.71	(15.2%)	(12.1%)	(8.9%)
2007	$57.58	$49.92	$34.60	16.9%	20.4%	5.8%
2008	$66.40	$55.53	$38.62	15.3%	11.2%	11.6%
2009	$37.08	$32.71	$17.12	(44.2%)	(41.1%)	(55.7%)
2010	$44.83	$36.88	$26.20	20.9%	12.7%	53.0%
2011	$42.84	$35.38	$29.03	(4.4%)	(4.1%)	10.8%
2012	$33.11	$29.53	$20.67	(22.7%)	(16.5%)	(28.8%)
2013	$36.55	$32.25	$20.57	10.4%	9.2%	(0.5%)
2014	$48.22	$34.46	$65.08	31.9%	6.9%	216.4%
2015	$33.39	$26.61	$27.80	(30.8%)	(22.8%)	(57.3%)
2016	$27.57	$24.10	$14.76	(17.4%)	(9.4%)	(46.9%)
2017	$29.42	$25.44	$17.40	6.7%	5.6%	17.9%
2018	$35.75	$28.28	$29.52	21.5%	11.2%	69.7%

106 The system average LMP is the average of the hourly LMP without any weighting. The only exception is that market-clearing prices (MCPs) are included for January to April 1998. MCP was the single market-clearing price calculated by PJM prior to implementation of LMP.

Real-Time, Load-Weighted, Average LMP

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

PJM Real-Time, Load-Weighted, Average LMP

Table 3-74 shows the PJM real-time, load-weighted, average LMP in 1998 through 2018.

Table 3-74 Real-time, load-weighted, average LMP (Dollars per MWh): 1998 through 2018

	Real-Time, Load-Weighted, Average LMP			Year-to-Year Change		
	Average	Median	Standard Deviation	Average	Median	Standard Deviation
1998	$24.16	$17.60	$39.29	NA	NA	NA
1999	$34.07	$19.02	$91.49	41.0%	8.1%	132.9%
2000	$30.72	$20.51	$28.38	(9.8%)	7.8%	(69.0%)
2001	$36.65	$25.08	$57.26	19.3%	22.3%	101.8%
2002	$31.60	$23.40	$26.75	(13.8%)	(6.7%)	(53.3%)
2003	$41.23	$34.96	$25.40	30.5%	49.4%	(5.0%)
2004	$44.34	$40.16	$21.25	7.5%	14.9%	(16.3%)
2005	$63.46	$52.93	$38.10	43.1%	31.8%	79.3%
2006	$53.35	$44.40	$37.81	(15.9%)	(16.1%)	(0.8%)
2007	$61.66	$54.66	$36.94	15.6%	23.1%	(2.3%)
2008	$71.13	$59.54	$40.97	15.4%	8.9%	10.9%
2009	$39.05	$34.23	$18.21	(45.1%)	(42.5%)	(55.6%)
2010	$48.35	$39.13	$28.90	23.8%	14.3%	58.7%
2011	$45.94	$36.54	$33.47	(5.0%)	(6.6%)	15.8%
2012	$35.23	$30.43	$23.66	(23.3%)	(16.7%)	(29.3%)
2013	$38.66	$33.25	$23.78	9.7%	9.3%	0.5%
2014	$53.14	$36.20	$76.20	37.5%	8.9%	220.4%
2015	$36.16	$27.66	$31.06	(32.0%)	(23.6%)	(59.2%)
2016	$29.23	$25.01	$16.12	(19.2%)	(9.6%)	(48.1%)
2017	$30.99	$26.35	$19.32	6.0%	5.4%	19.9%
2018	$38.24	$29.55	$32.89	23.4%	12.1%	70.2%

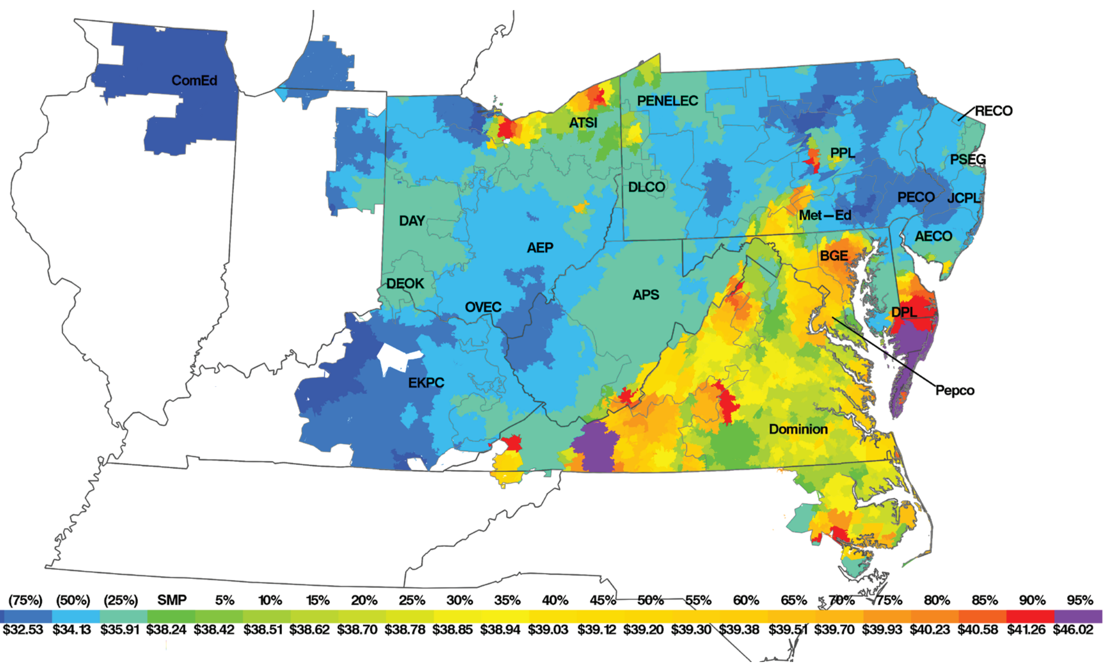
Table 3-75 shows zonal real-time, and real-time, load-weighted, average LMP in 2017 and 2018.

Table 3-75 Zonal real-time and real-time, load-weighted, average LMP (Dollars per MWh): 2017 and 2018

	Real-Time Average LMP			Real-Time, Load-Weighted, Average LMP		
Zone	2017	2018	Percent Change	2017	2018	Percent Change
AECO	$27.82	$34.84	25.3%	$29.63	$37.10	25.2%
AEP	$29.01	$35.61	22.7%	$30.17	$37.84	25.4%
APS	$29.81	$36.97	24.0%	$31.32	$39.83	27.2%
ATSI	$29.90	$37.89	26.7%	$31.23	$40.24	28.8%
BGE	$32.52	$40.27	23.8%	$34.76	$44.09	26.8%
ComEd	$26.83	$28.59	6.6%	$28.29	$30.08	6.3%
Day	$29.67	$36.59	23.3%	$31.06	$39.00	25.6%
DEOK	$29.02	$36.53	25.9%	$30.55	$39.20	28.3%
DLCO	$29.24	$37.60	28.6%	$33.49	$43.22	29.1%
Dominion	$31.44	$39.12	24.4%	$33.39	$43.82	31.2%
DPL	$30.66	$38.96	27.1%	$30.63	$40.03	30.7%
EKPC	$27.89	$33.25	19.2%	$29.19	$36.24	24.2%
JCPL	$28.40	$34.35	21.0%	$30.74	$37.11	20.7%
Met-Ed	$29.05	$34.15	17.6%	$31.15	$37.10	19.1%
OVEC	NA	$31.10	NA	NA	$30.61	NA
PECO	$27.90	$33.69	20.7%	$29.80	$36.40	22.1%
PENELEC	$29.21	$35.82	22.6%	$30.48	$37.95	24.5%
Pepco	$31.70	$39.18	23.6%	$33.70	$42.65	26.6%
PPL	$28.01	$32.97	17.7%	$29.99	$35.99	20.0%
PSEG	$29.05	$34.54	18.9%	$30.92	$36.72	18.8%
RECO	$29.13	$34.98	20.1%	$31.26	$37.43	19.7%
PJM	$29.42	$35.75	21.5%	$30.99	$38.24	23.4%

Figure 3-50 is a contour map of the real-time, load-weighted, average LMP in 2018. In the legend, green represents the system marginal price (SMP) and each increment to the right and left of the SMP represents five percent of the pricing nodes above and below the SMP. The LMP for each five percent increment is the highest nodal average LMP for that set of nodes. Each increment to the left of the SMP is the lowest nodal average LMP for that set of nodes.

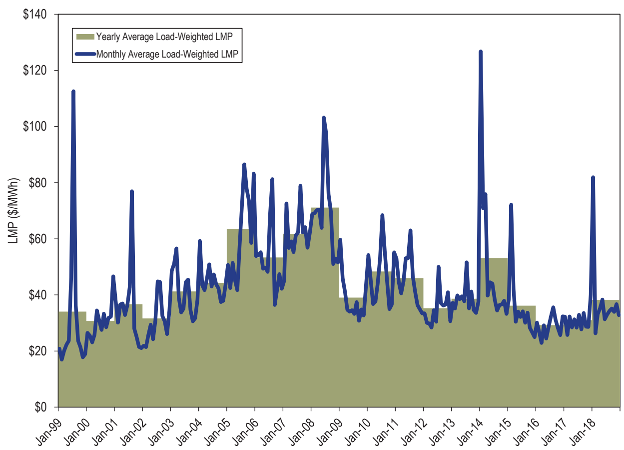
Figure 3-50 Real-time, load-weighted, average LMP: 2018



PJM Real-Time, Monthly, Load-Weighted, Average LMP

Figure 3-51 shows the PJM real-time monthly and annual load-weighted LMP for January 1999 through December 2018.

Figure 3-51 Real-time, monthly and annual, load-weighted, average LMP: January 1999 through December 2018



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

Figure 3-52 shows the PJM real-time monthly load-weighted average LMP and inflation adjusted monthly load-weighted average LMP for 1998, through December 2018.[107] Table 3-76 shows the PJM real-time load-weighted average LMP and inflation adjusted yearly load-weighted average LMP for every year starting from 1998 through 2018.

107 To obtain the inflation adjusted monthly load-weighted average LMP, the PJM system-wide load-weighted average LMP is deflated using the US Consumer Price Index for all items, Urban Consumers (base period: January 1998), published by *Bureau of Labor Statistics*. <http://download.bls.gov/pub/time.series/cu/cu.data.1.AllItems> (Accessed January 1 2019)

Figure 3-52 Real-time, monthly, load-weighted, average LMP unadjusted and adjusted for inflation: 1998 through 2018

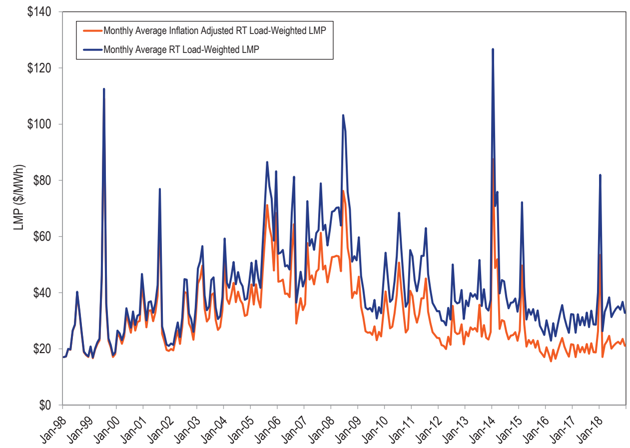


Table 3-76 Real-time, yearly, load-weighted, average LMP unadjusted and adjusted for inflation: 1998 through 2018

	Load-Weighted, Average LMP	Inflation Adjusted Load-Weighted, Average LMP
1998	$24.16	$23.94
1999	$34.07	$33.04
2000	$30.72	$28.80
2001	$36.65	$33.45
2002	$31.60	$28.35
2003	$41.23	$36.24
2004	$44.34	$37.91
2005	$63.46	$52.37
2006	$53.35	$42.73
2007	$61.66	$48.06
2008	$71.13	$53.27
2009	$39.05	$29.46
2010	$48.35	$35.83
2011	$45.94	$33.01
2012	$35.23	$24.80
2013	$38.66	$26.82
2014	$53.14	$36.37
2015	$36.16	$24.69
2016	$29.23	$19.68
2017	$30.99	$20.43
2018	$38.24	$24.65

Fuel Price Trends and LMP

In a competitive market, changes in LMP should follow changes in the marginal costs of marginal units, the units setting LMP. In general, fuel costs make up between 80 percent and 90 percent of short run marginal cost depending on generating technology, unit efficiency, unit age and other factors. The impact of fuel cost on marginal cost and on LMP depends on the fuel burned by marginal units and changes in fuel costs. Fuel prices rose in 2018 compared to 2017, but LMPs rose even more. Changes in emission allowance costs are another contributor to changes in the marginal cost of marginal units. Eastern natural gas prices and coal prices increased 2018 compared to 2017. The price of Northern Appalachian coal was 10.0 percent higher; the price of Central Appalachian coal was 12.0 percent higher; the price of Powder River Basin coal was 2.8 percent higher; the price of eastern natural gas was 43.8 percent higher; and the price of western natural gas was 10.1 percent higher. Figure 3-53 shows monthly average spot fuel prices.[108]

Figure 3-53 Spot average fuel price comparison with fuel delivery charges: January 2012 through December 2018 ($/MMBtu)

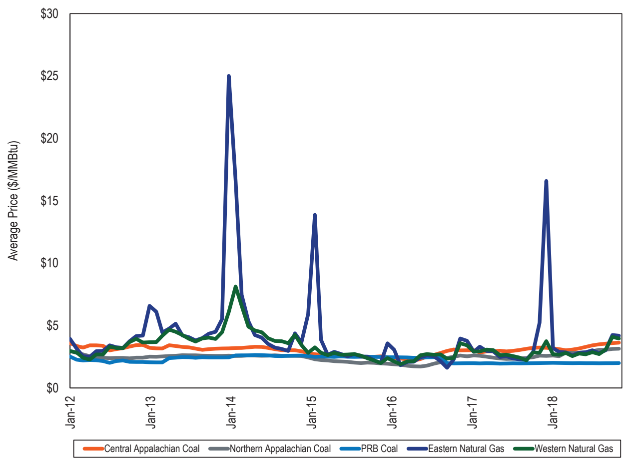


Table 3-77 compares the 2018 PJM real-time fuel-cost adjusted, load-weighted, average LMP to 2018 load-weighted, average LMP.[109] The real-time, load-weighted, average LMP for 2018 increased by $7.25 or 23.4 percent from real-time load-weighted average LMP for 2017. The real-time load-weighted, average LMP for 2018 was 7.2 percent higher than the real-time fuel-cost adjusted, load-weighted, average LMP for 2018. The real-time, fuel-cost adjusted, load-weighted, average LMP for 2018 was 15.1 percent higher than the real-time load-weighted LMP for 2017. If fuel and emissions costs in 2018 had been the same as in 2017, holding everything else constant, the real-time load-weighted LMP in 2018 would have been lower, $35.68 per MWh, than the observed $38.24 per MWh. Only 35 percent of the increase in LMP, $2.57 per MWh out of $7.25 per MWh, is directly attributable to fuel costs. Contributors to the other $4.69 per MWh are increased load, adjusted dispatch, and higher markups.

Table 3-77 Real-time, fuel-cost adjusted, load-weighted average LMP (Dollars per MWh): 2017 and 2018

	2018 Fuel-Cost Adjusted, Load-Weighted LMP	2018 Load-Weighted LMP	Change	Percent Change
Average	$35.68	$38.24	$2.57	7.2%
	2017 Load-Weighted LMP	**2018 Fuel-Cost Adjusted, Load-Weighted LMP**	**Change**	**Percent Change**
Average	$30.99	$35.68	$4.69	15.1%
	2017 Load-Weighted LMP	**2018 Load-Weighted LMP**	**Change**	**Change**
Average	$30.99	$38.24	$7.25	23.4%

Table 3-78 shows the impact of each fuel type on the difference between the fuel-cost adjusted, load-weighted average LMP and the load-weighted LMP in 2018. Table 3-78 shows that higher natural gas prices explain most of the fuel-cost related increase in the real-time annual load-weighted average LMP in 2018 from 2017.

Table 3-78 Change in real-time, fuel-cost adjusted, load-weighted average LMP ($/MWh) by fuel type: 2017 to 2018

Fuel Type	Share of Change in Fuel Cost Adjusted, Load Weighted LMP	Percent
Gas	$2.02	78.8%
Oil	$0.28	10.9%
Coal	$0.27	10.3%
Uranium	$0.00	0.0%
Municipal Waste	$0.00	0.0%
Other	$0.00	0.0%
NA	$0.00	0.0%
Wind	$0.00	0.0%
Total	$2.57	100.0%

Table 3-79 shows the 2018 PJM real-time fuel-cost adjusted, load-weighted, average LMP using 2017, 2016, 2015 and 2014 fuel and emission costs. If fuel and emissions costs in 2018 had been the same as in 2014, holding everything else constant, the real-time load-weighted LMP in 2018 would have been higher, $41.55 per MWh, than the observed $38.24 per MWh. If only fuel and emission costs of natural gas units in 2018 had been the same as in 2014, holding everything else constant, the real-time load-weighted LMP in 2018 would have been higher, $40.93 per MWh, than the observed $38.24 per MWh.

108 Eastern natural gas consists of the average of Texas M3, Transco Zone 6 non-NY, Transco Zone 6 NY and Transco Zone 5 daily fuel price indices. Western natural gas prices are the average of Dominion North Point, Columbia Appalachia and Chicago Citygate daily fuel price indices. Coal prices are the average of daily fuel prices for Central Appalachian coal, Northern Appalachian coal, and Powder River Basin coal. All fuel prices are from Platts.

109 The fuel-cost adjusted LMP reflects both the fuel and emissions where applicable, including NO_x, CO_2 and SO_x, costs.

Table 3-79 Historical Real-time, fuel-cost adjusted, load-weighted average LMP by Fuel Type (Dollars per MWh): 2014 through 2018

	2018 Fuel-Cost Adjusted, Load Weighted LMP			
	All Units	Gas Units	Coal Units	Oil Units
2018 Fuel and Emission Costs	$38.24	$38.24	$38.24	$38.24
2017 Fuel and Emission Costs	$35.68	$36.22	$37.98	$37.96
2016 Fuel and Emission Costs	$32.76	$33.98	$37.62	$37.65
2015 Fuel and Emission Costs	$34.21	$34.73	$37.71	$38.25
2014 Fuel and Emission Costs	$41.55	$40.93	$38.17	$38.93

Components of Real-Time, Load-Weighted LMP

LMPs result from the operation of a market based on security-constrained, economic (least-cost) dispatch (SCED) in which marginal units determine system LMPs, based on their offers and five minute ahead forecasts of system conditions. Those offers can be decomposed into components including fuel costs, emission costs, variable operation and maintenance (VOM) costs, markup, FMU adder and the 10 percent cost adder. As a result, it is possible to decompose LMP by the components of unit offers.

Cost offers of marginal units are separated into their component parts. The fuel related component is based on unit specific heat rates and spot fuel prices. Emission costs are calculated using spot prices for NO_x, SO_2 and CO_2 emission credits, emission rates for NO_x, emission rates for SO_2 and emission rates for CO_2. The CO_2 emission costs are applicable to PJM units in the PJM states that participate in RGGI: Delaware and Maryland.[110] The FMU adder is the calculated contribution of the FMU and AU adders to LMP that results when units with FMU or AU adders are marginal.

Since the implementation of scarcity pricing on October 1, 2012, PJM jointly optimizes the commitment and dispatch of energy and ancillary services. In periods of scarcity when generators providing energy have to be dispatched down from their economic operating level to meet reserve requirements, the joint optimization of energy and reserves takes into account the opportunity cost of the reduced generation and the associated incremental cost to maintain reserves. If a unit incurring such opportunity costs is a marginal resource in the energy market, this opportunity cost will contribute to LMP. In addition, in periods when generators providing energy cannot meet the reserve requirements, PJM can invoke shortage pricing. PJM invoked shortage pricing on January 6, January 7 of 2014 and September 21 of 2017.[111] During the shortage conditions, the LMPs of marginal generators reflect the cost of not meeting the reserve requirements, the scarcity adder, which is defined by the operating reserve demand curve.

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

Table 3-82 shows the frequency and average shadow price of transmission constraints in PJM. In 2018, there were 163,319 transmission constraints in the real-time market with a non-zero shadow price. For nearly 11 percent of these transmission constraints, the line limit was violated, meaning that the flow exceeded the facility limit.[112] In 2018, the average shadow price of transmission constraints when the line limit was violated was nearly six times higher than when transmission constraint was binding at its limit.

Transmission penalty factors should be stated explicitly and publicly and applied without discretion. Penalty factors should be set high enough so that they do not act to suppress prices based on available generator solutions. But rather than permit the transmission penalty factor to set the shadow price when line limits are violated, PJM has been using a procedure called constraint relaxation logic to prevent the penalty factors from directly setting the shadow price of the constraint. The result is that the transmission penalty factors have not directly set the shadow price through 2018. In 2018, for all the violated transmission constraints for which the penalty factor was greater than or equal to $2,000 per MWh, 44 percent of the constraints' shadow prices were within 10 percent of the penalty factor.

110 New Jersey withdrew from RGGI, effective January 1, 2012 and rejoined RGGI, effective January 29, 2018.

111 PJM triggered shortage pricing on January 6, 2015, following a RTO-wide voltage reduction action. PJM triggered shortage pricing on January 7, 2014, due to a RTO-wide shortage of synchronized reserve. PJM triggered shortage pricing on September 21, 2017 due to a sudden decrease in imports from neighboring regions.

112 The line limit of a facility associated with a transmission constraint is not necessarily the rated line limit. In PJM, the dispatcher has the discretion to lower the rated line limit.

The MMU recommended 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. PJM adopted the MMU's recommendation to remove the constraint relaxation logic and allow transmission penalty factors to set prices in the day ahead and real time markets for all internal transmission constraints. PJM also revised the tariff to list the conditions under which transmission penalty factors would be changed from their default value of $2,000 per MWh. The new rules went into effect on February 1, 2019. PJM has not yet adopted the same MMU recommendation for reciprocally coordinated market to market constraints with neighboring RTOs. PJM continues the practice of discretionary reduction in line ratings.

The components of LMP are shown in Table 3-80, including markup using unadjusted cost-based offers.[113] Table 3-80 shows that in 2018, 19.4 percent of the load-weighted LMP was the result of coal costs, 42.4 percent was the result of gas costs and 0.66 percent was the result of the cost of emission allowances. Using adjusted cost-based offers, markup was 19.0 percent of the load-weighted LMP. The fuel-related components of LMP reflect the degree to which the cost of the identified fuel affects LMP and does not reflect the other components of the offers of units burning that fuel. The component NA is the unexplained portion of load-weighted LMP. For several intervals, PJM fails to provide all the data needed to accurately calculate generator sensitivity factors. As a result, the LMP for those intervals cannot be decomposed into component costs. The cumulative effect of excluding those five-minute intervals is the component NA. In 2018, nearly 23 percent of all five-minute intervals had insufficient data. The percent column is the difference in the proportion of LMP represented by each component between 2018 and 2017.

Table 3-80 Components of real-time (Unadjusted), load-weighted, average LMP: 2017 and 2018

	2017		2018		
Element	Contribution to LMP	Percent	Contribution to LMP	Percent	Change Percent
Gas	$12.15	39.2%	$16.22	42.4%	3.2%
Coal	$8.97	28.9%	$7.43	19.4%	(9.5%)
Markup	$2.55	8.2%	$4.56	11.9%	3.7%
Ten Percent Adder	$2.39	7.7%	$2.73	7.1%	(0.6%)
NA	$0.81	2.6%	$1.88	4.9%	2.3%
Oil	$0.44	1.4%	$1.74	4.5%	3.1%
VOM	$1.70	5.5%	$1.46	3.8%	(1.7%)
Increase Generation Adder	$0.39	1.2%	$0.80	2.1%	0.8%
LPA Rounding Difference	$0.78	2.5%	$0.60	1.6%	(0.9%)
Ancillary Service Redispatch Cost	$0.25	0.8%	$0.44	1.2%	0.3%
CO_2 Cost	$0.09	0.3%	$0.16	0.4%	0.1%
Municipal Waste	$0.05	0.2%	$0.10	0.3%	0.1%
Opportunity Cost Adder	$0.04	0.1%	$0.10	0.3%	0.1%
NO_x Cost	$0.41	1.3%	$0.09	0.2%	(1.1%)
Other	$0.06	0.2%	$0.06	0.1%	(0.0%)
Scarcity Adder	$0.05	0.2%	$0.02	0.1%	(0.1%)
SO_2 Cost	$0.06	0.2%	$0.01	0.0%	(0.2%)
Market-to-Market Adder	$0.00	0.0%	$0.01	0.0%	0.0%
Constraint Violation Adder	$0.00	0.0%	($0.00)	(0.0%)	(0.0%)
Uranium	$0.00	0.0%	($0.00)	(0.0%)	(0.0%)
Wind	($0.11)	(0.4%)	($0.01)	(0.0%)	0.3%
LPA-SCED Differential	($0.01)	(0.0%)	($0.02)	(0.0%)	(0.0%)
Renewable Energy Credits	$0.00	0.0%	($0.03)	(0.1%)	(0.1%)
Decrease Generation Adder	($0.07)	(0.2%)	($0.10)	(0.3%)	(0.0%)
Total	$30.99	100.0%	$38.24	100.0%	0.0%

In order to accurately assess the markup behavior of market participants, real-time and day-ahead LMPs are decomposed using two different approaches. In the first approach (Table 3-80 and Table 3-87), markup is simply the difference between the price offer and the cost-based offer (unadjusted markup). In the second approach (Table 3-81 and Table 3-88), the 10 percent markup is removed from the cost-based offers of coal gas and oil units (adjusted markup).

The components of LMP are shown in Table 3-81, including markup using adjusted cost-based offers.

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

Table 3-81 Components of real-time (Adjusted), load-weighted, average LMP: 2017 and 2018

	2017		2018		
Element	Contribution to LMP	Percent	Contribution to LMP	Percent	Change Percent
Gas	$12.16	39.2%	$16.22	42.4%	3.2%
Coal	$8.97	28.9%	$7.43	19.4%	(9.5%)
Markup	$4.94	16.0%	$7.27	19.0%	3.1%
NA	$0.81	2.6%	$1.88	4.9%	2.3%
Oil	$0.44	1.4%	$1.74	4.5%	3.1%
VOM	$1.70	5.5%	$1.46	3.8%	(1.7%)
Increase Generation Adder	$0.39	1.2%	$0.80	2.1%	0.8%
LPA Rounding Difference	$0.80	2.6%	$0.60	1.6%	(1.0%)
Ancillary Service Redispatch Cost	$0.25	0.8%	$0.44	1.2%	0.3%
CO_2 Cost	$0.09	0.3%	$0.16	0.4%	0.1%
Municipal Waste	$0.05	0.2%	$0.10	0.3%	0.1%
Opportunity Cost Adder	$0.02	0.1%	$0.10	0.3%	0.2%
NO_x Cost	$0.41	1.3%	$0.09	0.2%	(1.1%)
Other	$0.06	0.2%	$0.06	0.1%	(0.0%)
Scarcity Adder	$0.05	0.2%	$0.02	0.1%	(0.1%)
Ten Percent Adder	$0.00	0.0%	$0.02	0.0%	0.0%
SO_2 Cost	$0.06	0.2%	$0.01	0.0%	(0.2%)
Market-to-Market Adder	$0.00	0.0%	$0.01	0.0%	0.0%
Constraint Violation Adder	$0.00	0.0%	($0.00)	(0.0%)	(0.0%)
Uranium	$0.00	0.0%	($0.00)	(0.0%)	(0.0%)
Wind	($0.11)	(0.4%)	($0.01)	(0.0%)	0.3%
LPA-SCED Differential	($0.01)	(0.0%)	($0.02)	(0.0%)	(0.0%)
Renewable Energy Credits	$0.00	0.0%	($0.03)	(0.1%)	(0.1%)
Decrease Generation Adder	($0.07)	(0.2%)	($0.10)	(0.3%)	(0.0%)
Total	$30.99	100.0%	$38.24	100.0%	0.0%

Table 3-82 Frequency and average shadow price of transmission constraints: 2017 and 2018

	Frequency		Average Shadow Price	
Description	2017	2018	2017	2018
PJM Internal Violated Transmission Constraints	12,405	17,548	$722.58	$1,151.09
PJM Internal Binding Transmission Constraints	102,571	96,309	$123.23	$203.48
Market to Market Transmission Constraints	47,558	49,462	$331.62	$368.69
Total	162,534	163,319		

Day-Ahead LMP

Day-ahead average LMP is the hourly average LMP for the PJM Day-Ahead Energy Market.[114]

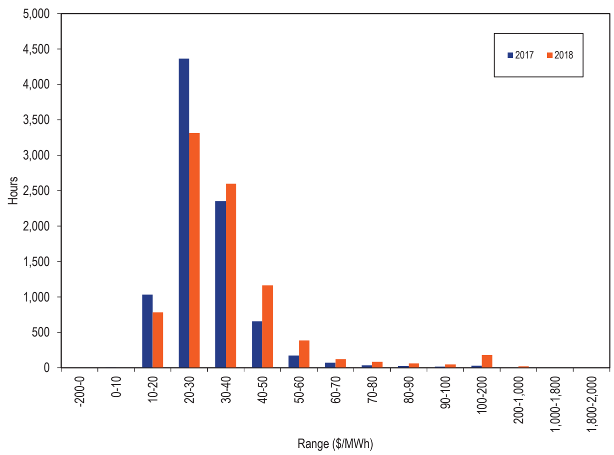
Day-Ahead Average LMP

PJM Day-Ahead Average LMP Duration

Figure 3-54 shows the hourly distribution of PJM day-ahead average LMP in 2017 and 2018.

114 See the *MMU Technical Reference for the PJM Markets*, at "Calculating Locational Marginal Price" for a detailed definition of Day-Ahead LMP. <http://www.monitoringanalytics.com/reports/Technical_References/references.shtml>.

Figure 3-54 Average LMP for the Day-Ahead Energy Market: 2017 and 2018



PJM Day-Ahead, Average LMP

Table 3-83 shows the PJM day-ahead, average LMP in 2000 through 2018.

Table 3-83 Day-ahead, average LMP (Dollars per MWh): 2000 through 2018

	Day-Ahead LMP			Year-to-Year Change		
	Average	Median	Standard Deviation	Average	Median	Standard Deviation
2000	$31.97	$24.42	$21.33	NA	NA	NA
2001	$32.75	$27.05	$30.42	NA	NA	NA
2002	$28.46	$23.28	$17.68	(13.1%)	(13.9%)	(41.9%)
2003	$38.73	$35.22	$20.84	36.1%	51.3%	17.9%
2004	$41.43	$40.36	$16.60	7.0%	14.6%	(20.3%)
2005	$57.89	$50.08	$30.04	39.7%	24.1%	81.0%
2006	$48.10	$44.21	$23.42	(16.9%)	(11.7%)	(22.0%)
2007	$54.67	$52.34	$23.99	13.7%	18.4%	2.4%
2008	$66.12	$58.93	$30.87	20.9%	12.6%	28.7%
2009	$37.00	$35.16	$13.39	(44.0%)	(40.3%)	(56.6%)
2010	$44.57	$39.97	$18.83	20.5%	13.7%	40.6%
2011	$42.52	$38.13	$20.48	(4.6%)	(4.6%)	8.8%
2012	$32.79	$30.89	$13.27	(22.9%)	(19.0%)	(35.2%)
2013	$37.15	$34.63	$15.46	13.3%	12.1%	16.5%
2014	$49.15	$38.10	$51.88	32.3%	10.0%	235.6%
2015	$34.12	$29.09	$22.59	(30.6%)	(23.7%)	(56.5%)
2016	$28.10	$25.76	$10.68	(17.7%)	(11.4%)	(52.7%)
2017	$29.48	$26.94	$11.69	4.9%	4.6%	9.5%
2018	$35.69	$30.96	$22.32	21.1%	14.9%	91.0%

Day-Ahead, Load-Weighted, Average LMP

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

PJM Day-Ahead, Load-Weighted, Average LMP

Table 3-84 shows the PJM day-ahead, load-weighted, average LMP in 2000 through 2018.

Table 3-84 Day-ahead, load-weighted, average LMP (Dollars per MWh): 2000 through 2018

	Day-Ahead, Load-Weighted, Average LMP			Year-to-Year Change		
	Average	Median	Standard Deviation	Average	Median	Standard Deviation
2000	$35.12	$28.50	$22.26	NA	NA	NA
2001	$36.01	$29.02	$37.48	NA	NA	NA
2002	$31.80	$26.00	$20.68	(11.7%)	(10.4%)	(44.8%)
2003	$41.43	$38.29	$21.32	30.3%	47.3%	3.1%
2004	$42.87	$41.96	$16.32	3.5%	9.6%	(23.5%)
2005	$62.50	$54.74	$31.72	45.8%	30.5%	94.4%
2006	$51.33	$46.72	$26.45	(17.9%)	(14.7%)	(16.6%)
2007	$57.88	$55.91	$25.02	12.8%	19.7%	(5.4%)
2008	$70.25	$62.91	$33.14	21.4%	12.5%	32.5%
2009	$38.82	$36.67	$14.03	(44.7%)	(41.7%)	(57.7%)
2010	$47.65	$42.06	$20.59	22.7%	14.7%	46.8%
2011	$45.19	$39.66	$24.05	(5.2%)	(5.7%)	16.8%
2012	$34.55	$31.84	$15.48	(23.5%)	(19.7%)	(35.6%)
2013	$38.93	$35.77	$18.05	12.7%	12.3%	16.6%
2014	$53.62	$39.84	$59.62	37.7%	11.4%	230.3%
2015	$36.73	$30.60	$25.46	(31.5%)	(23.2%)	(57.3%)
2016	$29.68	$27.00	$11.64	(19.2%)	(11.8%)	(54.3%)
2017	$30.85	$28.21	$12.64	3.9%	4.5%	8.6%
2018	$37.97	$32.49	$24.76	23.1%	15.2%	95.9%

Table 3-85 shows zonal day-ahead, and day-ahead, load-weighted, average LMP in 2017 and 2018.[115]

Table 3-85 Zonal day-ahead and day-ahead, load-weighted, average LMP (Dollars per MWh): 2017 and 2018

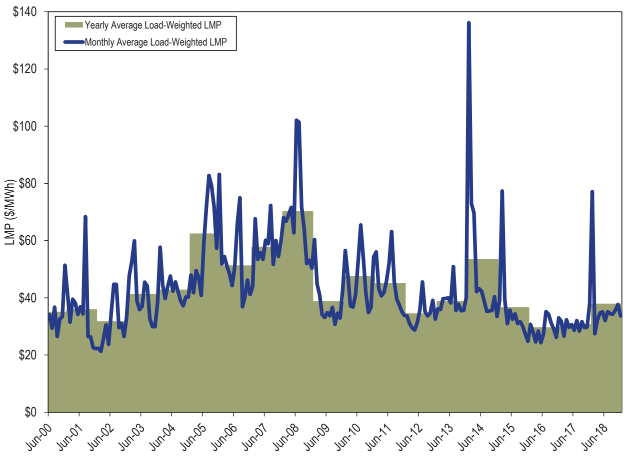
	Day-Ahead Average LMP			Day-Ahead, Load-Weighted, Average LMP		
Zone	2017	2018	Percent Change	2017	2018	Percent Change
AECO	$27.63	$34.69	25.6%	$29.14	$36.74	26.1%
AEP	$29.42	$35.45	20.5%	$30.56	$37.49	22.7%
APS	$29.91	$36.86	23.2%	$31.17	$39.18	25.7%
ATSI	$30.06	$37.13	23.5%	$31.23	$39.06	25.1%
BGE	$32.76	$40.41	23.4%	$34.78	$43.83	26.0%
ComEd	$26.94	$28.67	6.4%	$28.24	$30.15	6.8%
Day	$30.08	$36.68	21.9%	$31.37	$38.89	23.9%
DEOK	$29.56	$37.36	26.4%	$31.00	$40.14	29.5%
DLCO	$31.69	$39.42	24.4%	$30.76	$39.14	27.2%
Dominion	$29.93	$38.22	27.7%	$33.59	$43.34	29.0%
DPL	$29.50	$37.01	25.4%	$32.18	$42.53	32.1%
EKPC	$28.53	$33.43	17.1%	$29.95	$36.04	20.3%
JCPL	$28.20	$34.36	21.9%	$29.92	$36.67	22.6%
Met-Ed	$28.83	$34.40	19.3%	$30.44	$36.81	20.9%
OVEC	NA	$31.71	NA	NA	NA	NA
PECO	$27.62	$33.76	22.2%	$28.97	$35.98	24.2%
PENELEC	$28.86	$35.43	22.8%	$29.98	$37.61	25.4%
Pepco	$32.04	$39.40	23.0%	$33.71	$42.65	26.5%
PPL	$27.82	$33.21	19.4%	$29.30	$35.71	21.9%
PSEG	$28.88	$34.89	20.8%	$30.47	$37.08	21.7%
RECO	$28.97	$35.15	21.3%	$30.66	$37.38	21.9%
PJM	$29.48	$35.69	21.1%	$30.85	$37.97	23.1%

115 The OVEC Zone did not have any day-ahead load in 2018.

PJM Day-Ahead, Monthly, Load-Weighted, Average LMP

Figure 3-55 shows the PJM day-ahead, monthly and annual, load-weighted LMP from June 1, 2000 through December 31, 2018.[116]

Figure 3-55 Day-ahead, monthly and annual, load-weighted, average LMP: June 2000 through December 2018



PJM Day-Ahead, Monthly, Inflation Adjusted Load-Weighted, Average LMP

Figure 3-58 shows the PJM day-ahead monthly load-weighted average LMP and inflation adjusted monthly day-ahead load-weighted average LMP for June 2000 through December 2018.[117] Table 3-86 shows the PJM day-ahead yearly load- weighted average LMP and inflation adjusted load-weighted average LMP for every year from 2001 through 2018.

116 Since the Day-Ahead Energy Market did not start until June 1, 2000, the day-ahead data for 2000 only includes data for the last seven months of that year.

117 To obtain the inflation adjusted monthly load-weighted average LMP, the PJM system-wide load-weighted average LMP is deflated using US Consumer Price Index for all items, Urban Consumers (base period: January 1998), published by *Bureau of Labor Statistics*. <http://download.bls.gov/pub/time.series/cu/cu.data.1.AllItems> (Accessed January 14, 2019).

Figure 3-56 Day-ahead, monthly, load-weighted, average LMP unadjusted and inflation adjusted: June 2000 through December 2018

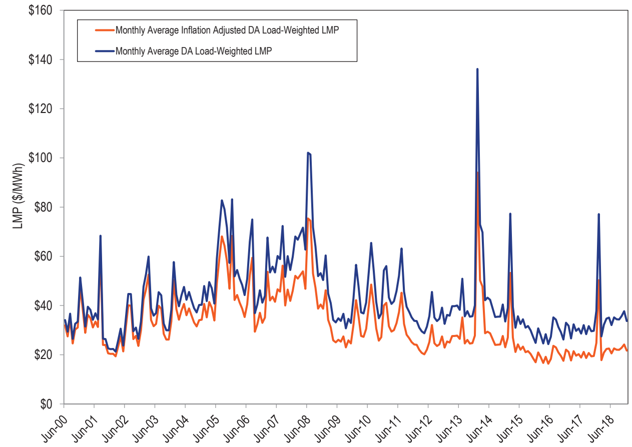


Table 3-86 Day-ahead, yearly, load-weighted, average LMP unadjusted and inflation adjusted: 2001 through 2018

	Load-Weighted, Average LMP	Inflation Adjusted Load-Weighted, Average LMP
2000	NA	NA
2001	$36.01	$32.87
2002	$31.80	$28.53
2003	$41.43	$36.42
2004	$42.87	$36.65
2005	$62.50	$51.58
2006	$51.33	$41.12
2007	$57.88	$45.11
2008	$70.25	$52.61
2009	$38.82	$29.29
2010	$47.65	$35.32
2011	$45.19	$32.48
2012	$34.55	$24.33
2013	$38.93	$27.00
2014	$53.62	$36.71
2015	$36.73	$25.08
2016	$29.68	$19.98
2017	$30.85	$20.34
2018	$37.97	$24.47

Components of Day-Ahead, Load-Weighted LMP

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

Cost-based offers of marginal units are separated into their component parts. The fuel related component is based on unit specific heat rates and spot fuel prices. Emission costs are calculated using spot prices for NO_X, SO_2 and CO_2 emission credits, emission rates for NO_X, emission rates for SO_2 and emission rates for CO_2. CO_2 emission costs are applicable to PJM units in the PJM states that participate in RGGI: Delaware, Maryland and New Jersey.[118] Day-ahead scheduling reserve (DASR), lost opportunity cost (LOC) and DASR offer adders are the calculated contribution to LMP when redispatch of resources is needed in order to satisfy DASR requirements.

Table 3-87 shows the components of the PJM day-ahead, annual, load-weighted average LMP. In 2018, 16.2 percent of the load-weighted LMP was the result of coal costs, 19.6 percent of the load-weighted LMP was the result of gas costs, 2.6 percent was the result of the up to congestion transaction costs, 28.4 percent was the result of DEC bid costs and 18.5 percent was the result of INC bid costs.

Table 3-87 Components of day-ahead, (unadjusted), load-weighted, average LMP (Dollars per MWh): 2017 and 2018

	2017		2018		
Element	Contribution to LMP	Percent	Contribution to LMP	Percent	Change Percent
DEC	$7.31	23.7%	$10.80	28.4%	4.7%
Gas	$5.69	18.4%	$7.45	19.6%	1.2%
INC	$6.86	22.2%	$7.02	18.5%	(3.7%)
Coal	$6.51	21.1%	$6.14	16.2%	(4.9%)
Ten Percent Cost Adder	$1.35	4.4%	$1.57	4.1%	(0.3%)
Markup	$0.72	2.3%	$1.22	3.2%	0.9%
VOM	$0.91	3.0%	$1.01	2.7%	(0.3%)
Up to Congestion Transaction	$0.94	3.1%	$0.97	2.6%	(0.5%)
Oil	$0.05	0.2%	$0.89	2.3%	2.2%
Dispatchable Transaction	$0.10	0.3%	$0.55	1.4%	1.1%
DASR LOC Adder	$0.06	0.2%	$0.13	0.3%	0.1%
CO_2	$0.05	0.2%	$0.10	0.3%	0.1%
NO_x	$0.26	0.9%	$0.07	0.2%	(0.7%)
Price Sensitive Demand	$0.00	0.0%	$0.06	0.1%	0.1%
SO_2	$0.03	0.1%	$0.01	0.0%	(0.1%)
Constrained Off	$0.00	0.0%	$0.00	0.0%	(0.0%)
Other	$0.01	0.0%	$0.00	0.0%	(0.0%)
Uranium	$0.00	0.0%	$0.00	0.0%	0.0%
Wind	($0.00)	(0.0%)	($0.00)	(0.0%)	0.0%
DASR Offer Adder	$0.01	0.0%	($0.02)	(0.0%)	(0.1%)
NA	$0.00	0.0%	$0.01	0.0%	0.0%
Total	$30.85	100.0%	$37.97	100.0%	(0.0%)

Table 3-88 shows the components of the PJM day-ahead, annual, load-weighted average LMP including the adjusted markup calculated by excluding the 10 percent adder from the coal, gas or oil units.

118 New Jersey withdrew from RGGI, effective January 1, 2012 and rejoined RGGI, effective January 29, 2018.

Table 3-88 Components of day-ahead, (adjusted), load-weighted, average LMP (Dollars per MWh): 2017 and 2018

	2017		2018		
Element	Contribution to LMP	Percent	Contribution to LMP	Percent	Change Percent
DEC	$7.31	23.7%	$10.80	28.4%	4.7%
Gas	$5.69	18.4%	$7.45	19.6%	1.2%
INC	$6.86	22.2%	$7.02	18.5%	(3.7%)
Coal	$6.51	21.1%	$6.14	16.2%	(4.9%)
Markup	$2.04	6.6%	$2.76	7.3%	0.7%
VOM	$0.91	3.0%	$1.01	2.7%	(0.3%)
Up to Congestion Transaction	$0.94	3.1%	$0.97	2.6%	(0.5%)
Oil	$0.05	0.2%	$0.89	2.3%	2.2%
Dispatchable Transaction	$0.10	0.3%	$0.55	1.4%	1.1%
DASR LOC Adder	$0.06	0.2%	$0.13	0.3%	0.1%
CO_2	$0.05	0.2%	$0.10	0.3%	0.1%
NO_x	$0.26	0.9%	$0.07	0.2%	(0.7%)
Price Sensitive Demand	$0.00	0.0%	$0.06	0.1%	0.1%
Ten Percent Cost Adder	$0.03	0.1%	$0.02	0.1%	(0.0%)
SO_2	$0.03	0.1%	$0.01	0.0%	(0.1%)
Constrained Off	$0.00	0.0%	$0.00	0.0%	(0.0%)
Other	$0.01	0.0%	$0.00	0.0%	(0.0%)
Uranium	$0.00	0.0%	$0.00	0.0%	0.0%
Wind	($0.00)	(0.0%)	($0.00)	(0.0%)	0.0%
DASR Offer Adder	$0.01	0.0%	($0.02)	(0.0%)	(0.1%)
NA	$0.00	0.0%	$0.01	0.0%	0.0%
Total	$30.85	100.0%	$37.97	100.0%	(0.0%)

Price Convergence

The introduction of the PJM Day-Ahead Energy Market with virtuals as part of the design created the possibility that competition, exercised through the use of virtual offers and bids, could tend to cause prices in the Day-Ahead and Real-Time Energy Markets to converge more than would be the case without virtuals. Convergence is not the goal of virtual trading, but it is a possible outcome. The degree of convergence, by itself, is not a measure of the competitiveness or effectiveness of the Day-Ahead Energy Market. Price convergence does not necessarily mean a zero or even a very small difference in prices between Day-Ahead and Real-Time Energy Markets. There may be factors, from operating reserve charges to differences in risk that result in a competitive, market-based differential. In addition, convergence in the sense that day-ahead and real-time prices are equal at individual buses or aggregates on a day to day basis is not a realistic expectation as a result of uncertainty, lags in response time and modeling differences, such as differences in modeled contingencies and marginal loss calculations, between the Day-Ahead and Real-Time Energy Market.

Where arbitrage opportunities are created by differences between day-ahead and real-time energy market expectations, reactions by market participants may lead to more efficient market outcomes but there is no guarantee that the results of virtual bids and offers will result in more efficient market outcomes.

Where arbitrage incentives are created by systematic modeling differences, such as differences between the day-ahead and real-time modeled transmission contingencies and marginal loss calculations, virtual bids and offers cannot result in more efficient market outcomes. Such offers may be profitable but cannot change the underlying reason for the price difference. The virtual transactions will continue to profit from the activity for that reason regardless of the volume of those transactions. This is termed false arbitrage.

INCs, DECs and UTCs allow participants to profit from price differences between the Day-Ahead and Real-Time Energy Market. Absent a physical position in real time, the seller of an INC must buy energy in the Real-Time Energy Market to fulfill the financial obligation to provide energy. If the day-ahead price for energy is higher than the real-time price for energy, the INC makes a profit. Absent a physical position in real time, the buyer of a DEC must sell energy in the Real-Time Energy Market to fulfill the financial obligation to buy energy. If the day-ahead price for energy is lower than the real-time price for energy, the DEC makes a profit.

The profitability of a UTC transaction is the net of the separate profitability of the component INC and DEC. A UTC can be net profitable if the profit on one side of the UTC transaction exceeds the losses on the other side.

Table 3-89 shows the number of cleared UTC transactions, the number of profitable cleared UTCs, the number of cleared UTCs that were profitable at their source point and the number of cleared UTCs that were profitable at their sink point in 2017 and 2018. In 2018, 49.2 percent of all cleared UTC transactions were net profitable. Of cleared UTC transactions, 65.1 percent were profitable on the source side and 35.5 were profitable on the sink side but only 5.7 percent were profitable on both the source and sink side.

Table 3-89 Cleared UTC profitability by source and sink point: 2017 and 2018[119]

	Cleared UTCs	Profitable UTCs	UTC Profitable at Source Bus	UTC Profitable at Sink Bus	UTC Profitable at Source and Sink	Profitable UTC	Profitable Source	Profitable Sink	Profitable at Source and Sink
2017	18,721,775	10,043,534	11,837,040	7,050,584	964,644	53.6%	63.2%	37.7%	5.2%
2018	9,782,432	4,810,016	6,372,542	3,470,802	555,684	49.2%	65.1%	35.5%	5.7%

Table 3-90 shows the number of cleared INC and DEC transactions, the number of profitable cleared transactions in 2017 and 2018. Of cleared INC and DEC transactions in 2018, 67.0 percent of INCs were profitable and 37.1 percent of DECs were profitable.

Table 3-90 Cleared INC and DEC profitability: 2017 and 2018

	Cleared INC	Profitable INC	Profitable INC	Cleared DEC	Profitable DEC	Profitable DEC
2017	2,240,631	1,446,494	64.6%	1,437,160	591,367	41.1%
2018	2,145,450	1,436,556	67.0%	1,539,329	570,717	37.1%

Figure 3-57 shows total UTC daily gross profits and losses and net profits and losses in 2018.

Figure 3-57 UTC daily gross profits and losses and net profits: 2018[120]

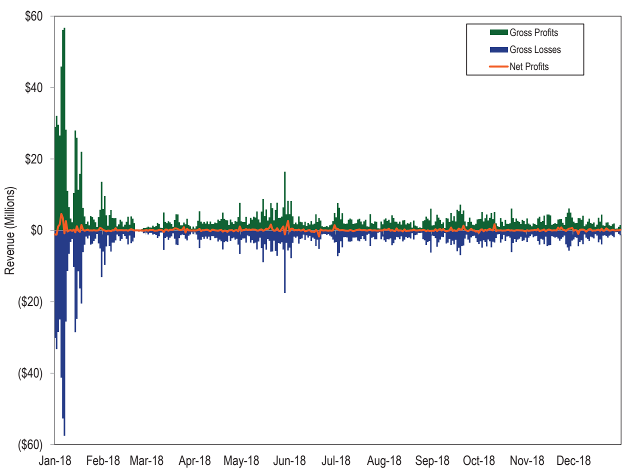


Figure 3-58 shows the cumulative UTC daily profits for January 1, 2013 through December 31, 2018. UTC profits during this period were primarily a result of significant unanticipated price differences between day ahead and real time LMPs. The large increases in cumulative daily UTC profits were due to PJM events that resulted in high real time LMPs. For example, the cumulative daily UTC profits in 2014 were greater than for the other three years as a result of profits from the significant and unanticipated day-ahead and real-time price differences that resulted from the polar vortex conditions in January 2014. The cumulative daily UTC profits increased during late February 2015 as a result of profits from the significant day-ahead and real-time prices differences that resulted from cold weather conditions. The cumulative daily UTC profits increased during late September and December 2017 as a result of profits from the significant day-ahead and real-time price difference that resulted from the shortage event on September 21, 2017 and cold weather in late December. Cumulative daily UTC profits increased significantly during the cold weather in January 2018 as a result of large day-ahead and real-time price differences.

Figure 3-58 Cumulative daily UTC profits: January 2013 through December 2018

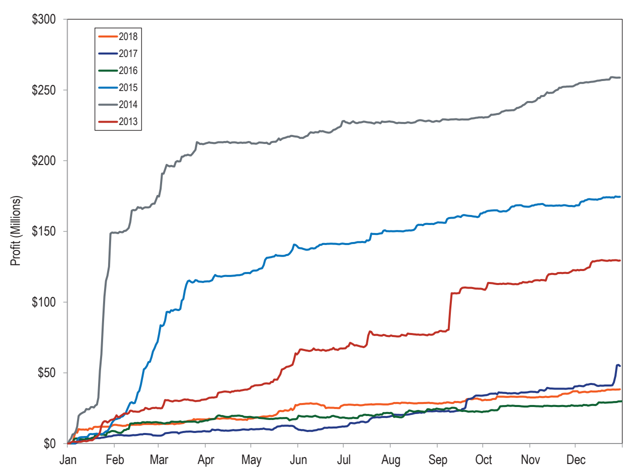


Table 3-91 shows UTC profits by month for January 1, 2013 through December 31, 2018. May 2016, September 2016, February 2017 and June 2018 were the only months in the past six years where the total monthly profits were negative.

119 Calculations exclude PJM administrative charges.
120 Calculations exclude PJM administrative charges.

Table 3-91 UTC profits by month: January 2013 through December 2018

	January	February	March	April	May	June	July	August	September	October	November	December	Total
2013	$17,048,654	$8,304,767	$5,629,392	$7,560,773	$25,219,947	$3,484,372	$8,781,526	$2,327,168	$31,160,618	$4,393,583	$8,730,701	$6,793,990	$129,435,490
2014	$148,973,434	$23,235,621	$39,448,716	$1,581,786	$3,851,636	$7,353,460	$3,179,356	$287,824	$2,727,763	$10,889,817	$11,042,443	$6,191,101	$258,762,955
2015	$16,132,319	$53,830,098	$44,309,656	$6,392,939	$19,793,475	$824,817	$8,879,275	$5,507,608	$6,957,012	$4,852,454	$392,876	$6,620,581	$174,493,110
2016	$8,874,363	$6,118,477	$1,119,457	$2,768,591	($1,333,563)	$841,706	$3,128,346	$3,200,573	($2,518,408)	$4,216,717	$254,684	$3,271,368	$29,942,312
2017	$5,716,757	($17,860)	$3,083,167	$944,939	$1,245,988	$868,400	$7,053,390	$4,002,063	$10,960,012	$2,360,817	$2,716,950	$15,936,217	$54,870,839
2018	$13,184,346	$506,509	$3,410,577	$688,796	$9,499,735	($768,614)	$1,163,380	$692,736	$2,845,649	$1,452,515	$4,339,363	$1,358,446	$38,373,436

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

Substantial virtual trading activity does not guarantee that market power cannot be exercised in the Day-Ahead Energy Market. Hourly and daily price differences between the Day-Ahead and Real-Time Energy Markets fluctuate continuously and substantially from positive to negative. There may be substantial, persistent differences between day-ahead and real-time prices even on a monthly basis (Figure 3-60).

Table 3-92 shows that the difference between the average real-time price and the average day-ahead price was -$0.06 per MWh in 2017, and $0.06 per MWh in 2018. The difference between average peak real-time price and the average peak day-ahead price was -$0.35 per MWh in 2017 and -$0.60 per MWh in 2018.

Table 3-92 Day-ahead and real-time average LMP (Dollars per MWh): 2017 and 2018[121]

	2017				2018			
	Day-Ahead	Real-Time	Difference	Percent of Real Time	Day-Ahead	Real-Time	Difference	Percent of Real Time
Average	$29.48	$29.42	($0.06)	(0.2%)	$35.69	$35.75	$0.06	0.2%
Median	$26.94	$25.44	($1.50)	(5.9%)	$30.96	$28.28	($2.68)	(9.5%)
Standard deviation	$11.69	$17.40	$5.71	32.8%	$22.32	$29.52	$7.20	24.4%
Peak average	$34.42	$34.07	($0.35)	(1.0%)	$41.41	$40.81	($0.60)	(1.5%)
Peak median	$31.97	$29.34	($2.63)	(9.0%)	$36.66	$32.99	($3.67)	(11.1%)
Peak standard deviation	$12.50	$20.17	$7.67	38.0%	$22.71	$28.01	$5.30	18.9%
Off peak average	$25.20	$25.39	$0.20	0.8%	$30.70	$31.33	$0.62	2.0%
Off peak median	$22.98	$22.57	($0.41)	(1.8%)	$25.43	$24.41	($1.03)	(4.2%)
Off peak standard deviation	$8.95	$13.33	$4.38	32.8%	$20.73	$30.10	$9.37	31.1%

The price difference between the Real-Time and the Day-Ahead Energy Markets results in part, from conditions in the Real-Time Energy Market that are difficult, or impossible, to anticipate in the Day-Ahead Energy Market.

Table 3-93 shows the difference between the real-time and the day-ahead energy market prices for 2001 through 2018.

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

Table 3-93 Day-ahead and real-time average LMP (Dollars per MWh): 2001 through 2018

	Day-Ahead	Real-Time	Difference	Percent of Real Time
2001	$32.75	$32.38	($0.37)	(1.1%)
2002	$28.46	$28.30	($0.16)	(0.6%)
2003	$38.73	$38.28	($0.45)	(1.2%)
2004	$41.43	$42.40	$0.97	2.3%
2005	$57.89	$58.08	$0.18	0.3%
2006	$48.10	$49.27	$1.17	2.4%
2007	$54.67	$57.58	$2.90	5.3%
2008	$66.12	$66.40	$0.28	0.4%
2009	$37.00	$37.08	$0.08	0.2%
2010	$44.57	$44.83	$0.26	0.6%
2011	$42.52	$42.84	$0.32	0.7%
2012	$32.79	$33.11	$0.32	1.0%
2013	$37.15	$36.55	($0.60)	(1.6%)
2014	$49.15	$48.22	($0.93)	(1.9%)
2015	$34.12	$33.39	($0.73)	(2.1%)
2016	$28.10	$27.57	($0.53)	(1.9%)
2017	$29.48	$29.42	($0.06)	(0.2%)
2018	$35.69	$35.75	$0.06	0.2%

Table 3-94 provides frequency distributions of the differences between PJM real-time hourly LMP and PJM day-ahead hourly LMP for 2017 and 2018.

Table 3-94 Frequency distribution by hours of real-time LMP minus day-ahead LMP (Dollars per MWh): 2017 and 2018

	2017		2018	
LMP	Frequency	Cumulative Percent	Frequency	Cumulative Percent
< ($1,000)	0	0.00%	0	0.00%
($1,000) to ($750)	0	0.00%	0	0.00%
($750) to ($500)	0	0.00%	0	0.00%
($500) to ($450)	0	0.00%	0	0.00%
($450) to ($400)	0	0.00%	0	0.00%
($400) to ($350)	0	0.00%	0	0.00%
($350) to ($300)	0	0.00%	0	0.00%
($300) to ($250)	0	0.00%	0	0.00%
($250) to ($200)	0	0.00%	0	0.00%
($200) to ($150)	0	0.00%	1	0.01%
($150) to ($100)	2	0.02%	3	0.05%
($100) to ($50)	9	0.13%	32	0.41%
($50) to $0	5,460	62.45%	5,715	65.65%
$0 to $50	3,231	99.34%	2,855	98.24%
$50 to $100	45	99.85%	112	99.52%
$100 to $150	8	99.94%	26	99.82%
$150 to $200	3	99.98%	5	99.87%
$200 to $250	0	99.98%	8	99.97%
$250 to $300	0	99.98%	1	99.98%
$300 to $350	0	99.98%	1	99.99%
$350 to $400	0	99.98%	0	99.99%
$400 to $450	1	99.99%	1	100.00%
$450 to $500	0	99.99%	0	100.00%
$500 to $750	1	100.00%	0	100.00%
$750 to $1,000	0	100.00%	0	100.00%
$1,000 to $1,250	0	100.00%	0	100.00%
>= $1,250	0	100.00%	0	100.00%

Figure 3-59 shows the hourly differences between day-ahead and real-time hourly LMP in 2018.

Figure 3-59 Real-time hourly LMP minus day-ahead hourly LMP: 2018

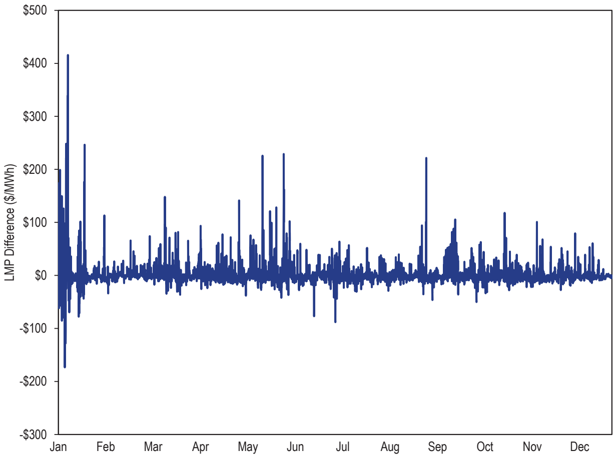


Figure 3-60 shows the monthly average of the differences between the day-ahead and real-time PJM average LMPs from January 1, 2013, through December 31, 2018.

Figure 3-60 Monthly average of real-time minus day-ahead LMP: January 2013 through December 2018

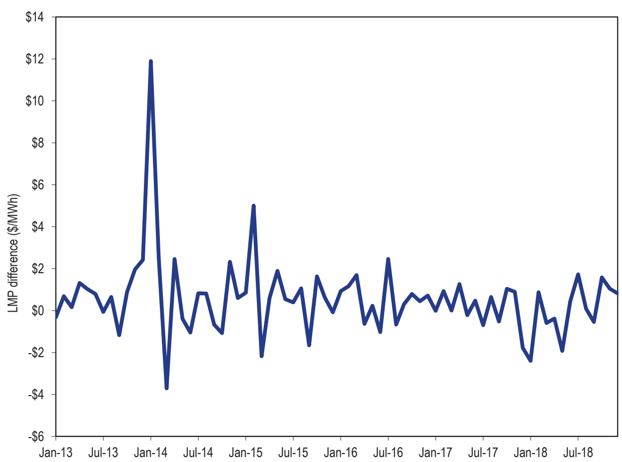


Figure 3-61 shows the monthly average of the absolute value of the differences between the day-ahead and real-time hourly, nodal LMPs from January 1, 2013, through December 31, 2018.

Figure 3-61 Monthly average of absolute value of real-time minus day-ahead LMP by pnode: January 2013 through December 2018

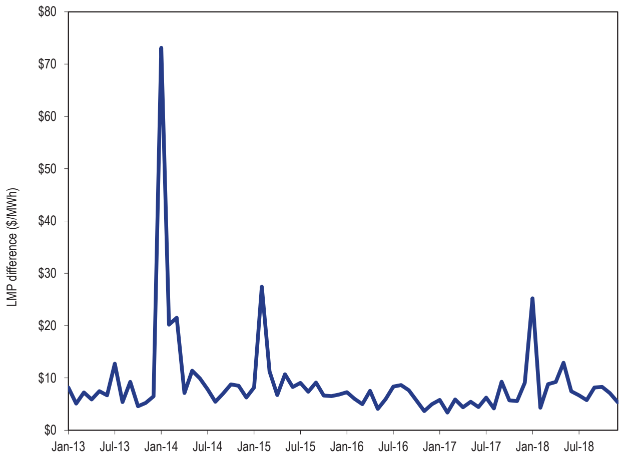
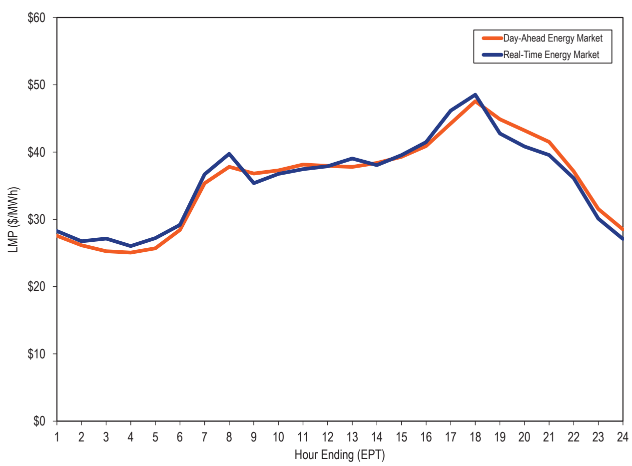


Figure 3-62 shows day-ahead and real-time LMP on an average hourly basis for 2018. Hour ending 20 had the largest difference between the DA and RT LMP, at $2.38 per MWh, and hour ending 12 had the smallest difference at $0.05 per MWh. The average for 2018 was $0.06 per MWh higher in the RT LMP than DA LMP.

Figure 3-62 System hourly average LMP: January through December, 2018



Scarcity

PJM's energy market experienced five minute shortage pricing events on two days in 2018. Table 3-95 shows a summary of the number of days emergency alerts, warnings and actions were declared in PJM in 2017 and 2018.

Table 3-95 Summary of emergency events declared: 2017 and 2018

	Number of days events declared	
Event Type	2017	2018
Cold Weather Alert	4	12
Hot Weather Alert	17	23
Maximum Emergency Generation Alert	0	0
Primary Reserve Alert	0	0
Voltage Reduction Alert	0	0
Primary Reserve Warning	0	0
Voltage Reduction Warning	0	0
Pre Emergency Mandatory Load Management Reduction Action	0	0
Emergency Mandatory Load Management Reduction Action (30, 60 or 120 minute lead time)	0	0
Maximum Emergency Action	0	0
Emergency Energy Bids Requested	0	0
Voltage Reduction Action	0	0
Shortage Pricing	1	2
Energy export recalls from PJM capacity resources	0	0

Figure 3-63 shows the number of days that weather and capacity emergency alerts were issued in PJM from 2014 through 2018. Figure 3-64 shows the number of days emergency warnings were issued and actions were taken in PJM from 2014 through 2018.

Figure 3-63 Declared emergency alerts: 2014 through 2018

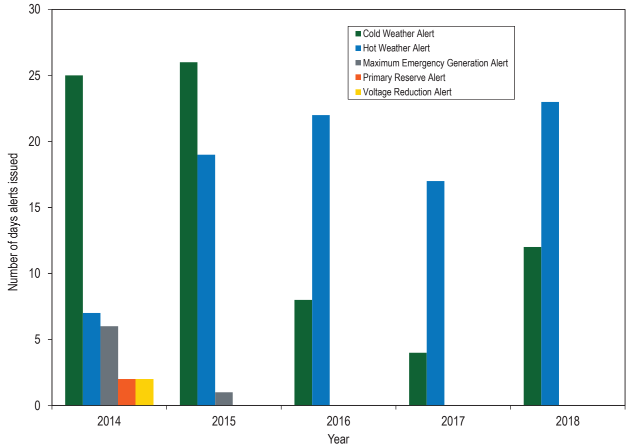
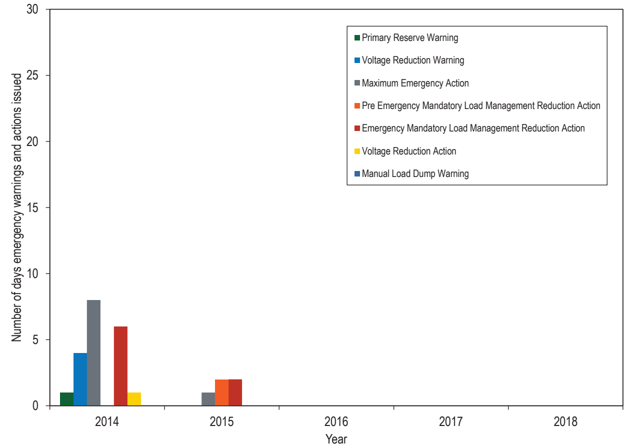


Figure 3-64 Declared emergency warnings and actions: 2014 through 2018



Emergency Procedures

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

PJM declared cold weather alerts on 12 days in 2018 compared to four days in 2017.[122] The purpose of a cold weather alert is to prepare personnel and facilities for expected extreme cold weather conditions, generally when temperatures are forecast to approach or fall below 10 degrees Fahrenheit.

PJM declared hot weather alerts on 23 days in 2018 compared to 17 days in 2017.[123] The purpose of a hot weather alert is to prepare personnel and facilities for expected extreme hot and humid weather conditions, generally when temperatures are forecast to exceed 90 degrees Fahrenheit with high humidity.

PJM did not declare any maximum emergency generation alerts in 2018 and 2017. The purpose of a maximum emergency generation alert is to provide an alert at least one day prior to the operating day that system conditions may require use of PJM emergency actions. It is called to alert PJM members that maximum emergency generation may be requested in the operating capacity.[124] This means that if PJM directs members to load maximum emergency generation during the operating day, the resources must be able to increase generation above the maximum economic level of their offer.

PJM did not declare any primary reserve alerts in 2018 and 2017. The purpose of a primary reserve alert is to alert members at least one day prior to the operating day that available primary reserves are anticipated to be short of the primary reserve requirement on the operating day.[125] It is issued when the estimated primary reserves are less than the forecast primary reserve requirement.

PJM did not declare any voltage reduction alerts in 2018 and 2017. The purpose of a voltage reduction alert is to alert members at least one day prior to the operating day that a voltage reduction may be required on the operating day.[126] It is issued when the estimated operating reserve is less than the forecast synchronized reserve requirement.

PJM did not declare any primary reserve warning in 2018 and 2017. The purpose of a primary reserve warning is to warn members that available primary reserves are less than the primary reserve requirement but greater than the synchronized reserve requirement.[127]

PJM did not declare any voltage reduction warnings or reductions of noncritical plant load in 2018 and 2017. The purpose of a voltage reduction warning and reduction of noncritical plant load is to warn members that available synchronized reserves are less than the synchronized reserve requirement and that a voltage reduction may be required. It can be issued for the RTO or for specific control zones.

PJM did not declare any emergency mandatory load management reductions in 2018 and 2017. The purpose of emergency mandatory load management is to request curtailment service providers (CSP) to implement load reductions from demand resources registered in PJM demand response programs that have a lead time of between one and two hours (long lead time) and a lead time of up to one hour (short lead time). Starting in June 2014, PJM combined the long lead and short lead emergency load management action procedures into Emergency Mandatory Load Management Reduction Action (30, 60 or 120 minute lead time). PJM dispatch declares NERC Energy Emergency Alert level 2 (EEA2) concurrent with Emergency Mandatory load Management Reductions. PJM also added a Pre-Emergency Mandatory Load Management Reduction Action (30, 60 or 120 minute lead time) step to request load reductions before declaring emergency load management reductions.[128]

PJM did not declare any maximum emergency generation actions in 2018 and 2017. The purpose of a maximum emergency generation action is to request generators to increase output to the maximum emergency level which

122 See PJM. "Manual 13: Emergency Operations,"§ 3.3 Cold Weather Alert, Rev. 68 (Jan. 1, 2019).
123 See PJM. "Manual 13: Emergency Operations," § 3.4 Hot Weather Alert, Rev. 68 (Jan. 1, 2019).
124 See PJM. "Manual 13: Emergency Operations," § 2.3.1 Advanced Notice Emergency Procedures: Alerts, Rev. 68 (Jan. 1, 2019).
125 *Id.*
126 *Id.*
127 See PJM. "Manual 13: Emergency Operations," § 2.3.2 Real-Time Emergency Procedures (Warnings and Actions), Rev. 68 (Jan. 1, 2019).
128 *Id.*

unit owners may define at a level above the maximum economic level.[129] A maximum emergency generation action can be issued for the RTO, for specific control zones or for parts of control zones.

PJM did not request any offers for emergency energy purchases in 2018 and 2017.

PJM did not declare any voltage reduction actions in 2018 and 2017. The purpose of a voltage reduction is to reduce load to provide sufficient reserves, to maintain tie flow schedules, and to preserve limited energy sources. When a voltage reduction action is issued for a reserve zone or subzone, the primary reserve penalty factor and synchronized reserve penalty factor are incorporated into the synchronized and nonsynchronized reserve market clearing prices and locational marginal prices until the voltage reduction action has been terminated.

PJM declared 18 synchronized reserve events in 2018 compared to 16 events in 2017.[130] Synchronized reserve events may occur at any time of the year due to sudden loss of generation or transmission facilities, or sudden loss of imports, and do not necessarily coincide with capacity emergency conditions such as maximum generation emergency events or emergency load management events.

Table 3-96 provides a description of PJM declared emergency procedures.

Table 3-96 Description of emergency procedures

Emergency Procedure	Purpose
Cold Weather Alert	To prepare personnel and facilities for extreme cold weather conditions, generally when forecast weather conditions approach minimum or temperatures fall below ten degrees Fahrenheit.
Hot Weather Alert	To prepare personnel and facilities for extreme hot and/or humid weather conditions, generally when forecast temperatures exceed 90 degrees with high humidity.
Maximum Emergency Generation Alert	To provide an early alert at least one day prior to the operating day that system conditions may require the use of the PJM emergency procedures and resources must be able to increase generation above the maximum economic level of their offers.
Primary Reserve Alert	To alert members of a projected shortage of primary reserve for a future period. It is implemented when estimated primary reserve is less than the forecast requirement.
Voltage Reduction Alert	To alert members that a voltage reduction may be required during a future critical period. It is implemented when estimated reserve capacity is less than forecasted synchronized reserve requirement.
Pre-Emergency Load Management Reduction Action	To request load reductions from customers registered in the PJM Demand Response program that need 30, 60, or 120 minute lead time before declaring emergency load management reductions
Emergency Mandatory Load Management Reduction Action	To request load reductions from customers registered in the PJM Demand Response program that need 30, 60, or 120 minute lead time to provide additional load relief, generally declared simultaneously with NERC Energy Emergency Alert Level 2 (EEA2)
Primary Reserve Warning	To warn members that available primary reserve is less than required and present operations are becoming critical. It is implemented when available primary reserve is less than the primary reserve requirement but greater than the synchronized reserve requirement.
Maximum Emergency Generation Action	To provide real time notice to increase generation above the maximum economic level. It is implemented whenever generation is needed that is greater than the maximum economic level.
Voltage Reduction Warning & Reduction of Non-Critical Plant Load	To warn members that actual synchronized reserves are less than the synchronized reserve requirement and that voltage reduction may be required.
Deploy All Resources Action	For emergency events that do not evolve over time, but rather develop rapidly and without prior warning, PJM issues this action to instruct all generation resources to be online immediately and to all load management resources to reduce load immediately.
Manual Load Dump Warning	To warn members of the critical condition of present operations that may require manually dumping load. Issued when available primary reserve capacity is less than the largest operating generator or the loss of a transmission facility jeopardizes reliable operations after all other possible measures are taken to increase reserve.
Voltage Reduction Action	To reduce load to provide sufficient reserve capacity to maintain tie flow schedules and preserve limited energy sources. It is implemented when load relief is needed to maintain tie schedules.
Manual Load Dump Action	To provide load relief when all other possible means of supplying internal PJM RTO load have been used to prevent a catastrophe within the PJM RTO or to maintain tie schedules so as not to jeopardize the reliability of the other interconnected regions.

129 *Id.*
130 See *2018 State of the Market Report for PJM*, Section 10: Ancillary Service Markets for details on the spinning events.

Table 3-97 shows the dates when emergency alerts and warnings were declared and when emergency actions were implemented in 2018.

Table 3-97 Declared emergency alerts, warnings and actions: 2018

Date	Cold Weather Alert	Hot Weather Alert	Maximum Emergency Generation Alert	Primary Reserve Alert	Voltage Reduction Alert	Primary Reserve Warning	Voltage Reduction Warning and Reduction of Non-Critical Plant Load	Maximum Emergency Generation Action	Pre-Emergency Mandatory Load Management Reduction	Emergency Mandatory Load Management Reduction	Voltage Reduction	Manual Load Dump Warning	Manual Load Dump Action	Load Shed Directive
1/1/2018	PJM RTO													
1/2/2018	PJM RTO													
1/3/2018	Western													
1/4/2018	Western													
1/5/2018	PJM RTO													
1/6/2018	PJM RTO													
1/7/2018	PJM RTO													
1/14/2018	Western													
1/16/2018	Western													
1/17/2018	Western													
2/5/2018	ComEd													
2/6/2018	ComEd													
5/3/2018		Mid Atlantic and Dominion												
5/4/2018		Mid Atlantic and Dominion												
5/28/2018		Western												
5/29/2018		Mid Atlantic and Western												AEP (Edison Area)
6/1/2018		Mid Atlantic and Dominion												
6/17/2018		Western												
6/18/2018		PJM RTO												
6/29/2018		PJM RTO												
6/30/2018		PJM RTO												
7/1/2018		PJM RTO												
7/2/2018		Mid Atlantic and Dominion												
7/3/2018		Mid Atlantic and Dominion												
7/10/2018		Mid Atlantic and Dominion												
7/14/2018		Mid Atlantic region, AEP, Dayton, DEOK, EKPC, APS, and ATSI zones												
7/15/2018		Mid Atlantic region, AEP, DEOK, Dominion and EKPC zones												
7/16/2018		Mid Atlantic and Dominion												
7/18/2018														AEP (Lonesone Pine area)
8/27/2018		Mid Atlantic Region, Dominion and ComEd zones												
8/28/2018		Mid Atlantic and Dominion												
8/29/2018		Mid Atlantic and Dominion												
8/30/2018		Dominion												
9/4/2018		PJM RTO												
9/5/2018		PJM RTO												
9/6/2018		Mid Atlantic and Dominion												

AEP Twin Branch Load Shed Event

On May 29, 2018, at 1322 EPT, PJM directed AEP, the local transmission owner, to shed 21 MW of load in the Edison area in northern Indiana to prevent a post contingency cascade condition. This action triggered a Performance Assessment Interval (PAI). The sequence of events that led to the load shed event point to important market design and operational issues including the lack of nodal dispatch for demand resources, and the inability to reflect the lack of supply resources in LMPs. The event also highlighted the importance for multiple contingency analyses in local areas where multiple planned outages, and simultaneous unplanned outages, can result in potential reliability issues.

On May 28, 2018, PJM issued a hot weather alert for the operating day of May 29, 2018 for the Mid-Atlantic and Western regions of PJM. There were three lines in the area that were out of service on planned outages on May 29, 2018.[131] PJM's (n-1) contingency analyses indicated no reliability concerns in the area and PJM did not initially recall these outages. At 1236 EPT, the Twin Branch – Jackson Road 138 kV Line and the Jackson Road 345/138 kV Transformer 3 tripped. At 1248 EPT, PJM operators identified contingency overloads on the Edison- Kankakee Line for two potential contingency scenarios. The first was due to the potential loss of the Twin Branch 6 and 7 transformers (modeled as a single contingency) and the second was due to the potential loss of the Twin Branch – South Bend 138 kV Line. At 1312 EPT, the second contingency scenario, with the potential loss of the Twin Branch – South Bend 138 kV Line, did not solve and indicated a potential cascade condition. At 1322 EPT, PJM directed AEP to shed load in the Edison area to reduce post contingency flows on the Edison – Kankakee line for the potential loss of the Twin Branch – South Bend 138 kV Line. At 1337 EPT, the Jackson Road 345/138 kV Transformer was restored, and at 1346, PJM canceled the load shed.

The load shed directive issued at 1322 EPT triggered a Performance Assessment Interval for the Edison area, under Capacity Performance rules, and was in effect until 1346 EPT, when PJM canceled the load shed directive. There were no generation resources in the area that could have provided relief to the post contingency flows on the Edison-Kankakee line. PJM operators could not dispatch any potential demand resources (DR) in the area because PJM has limited visibility of DR at the nodal level, and cannot dispatch DR at a level more granular than a zone unless the area is predefined as a DR subzone. In this instance, there were no subzones defined as DR subzones in the Edison area. This prevented PJM operators from potentially dispatching demand resources during the emergency event. If PJM were to call on demand resources for the entire AEP Zone, under Capacity Performance rules, it would have triggered a Performance Assessment Interval in the entire AEP Zone, which would not have reflected the local reliability issue in the Edison area, and would have caused generation resources outside the Edison area to produce more energy than needed. This event illustrates the inconsistency of treating capacity resources differently that are treated in the capacity market as full substitutes for other capacity resources and that receive the same capacity revenues but have different obligations to perform in the energy market. The MMU recommends that demand resources be modeled nodally and be required to be nodally dispatchable, similar to generation resources.

The Twin Branch event points to the implications of not having locational scarcity pricing. PJM did not have any additional supply in the Edison area to provide relief to the Edison – Kankakee line, and subsequently had to shed load for reliability, but the LMPs in the area did not reflect the local supply and demand conditions. In instances where there are multiple planned outages or reliability concerns, PJM should determine whether to model constraints in the energy market that reflect (n-2) or (n-3) contingency flow limits. In the absence of supply or demand resources to solve for the (n-2) or (n-3) contingency flow limits, the transmission limit penalty factor associated with those constraints would have set prices in the Edison area.

When transmission outage requests are received, PJM analyzes the reliability conditions due to outages before approving them. In this instance, PJM analyzed the system in the area and found no issues with (n-1) contingency analysis with the three planned outages. However, the unplanned outages of the Twin Branch – Jackson Road 138 kV Line and the Jackson Road 345/138 kV Transformer 3, in combination with the three

131 See PJM, "Twin Branch / Edison Area Load Shed Event May 29, 2018," Presented to the System Operations Subcommittee (July 5, 2018) <http://www.pjm.com/-/media/committees-groups/subcommittees/sos/20180705/20180705-item-04-twin-branch-area-load-shed.ashx>.

planned line outages, indicated a potential for a cascade condition from the potential loss of one more facility. PJM should explore conducting reliability analyses in local areas with multiple simultaneous planned outages that go beyond an (n-1) contingency study to account for issues that may arise due to simultaneous unplanned outages.

AEP Lonesome Pine Load Shed Event

On July 18, 2018, at 1052 EPT, PJM directed AEP, the local transmission owner, to shed load in the Lonesome Pine - Bluefield area in Virginia and West Virginia to return voltages from below load dump levels to acceptable levels. This action triggered a Performance Assessment Interval (PAI) from 1114 EPT, when AEP shed load, to 1237 EPT when the load was restored. AEP shed 32 MW of load during this period that affected customers in Virginia and West Virginia. There were no generation resources in the area that could have provided the needed local voltage support.

The low voltage resulted from a combination of a scheduled transmission facility outage that started on July 16, 2018 (Buckhorn – Lonesome Pine 138 kV line) and an unplanned trip of the Glen Lyn 138 kV bus on July 18, 2018 at 0937 EPT. This resulted in a radial load pocket in the Lonesome Pine area. The trip of the Glen Lyn 138 kV bus resulted in automatic switching in service of a capacitor at South Bluefield that led to a voltage spike that resulted in a trip of that capacitor and another capacitor at South Princeton at 1052 EPT. This led to the voltage levels in the Lonesome Pine area to fall 5 kV below the load dump level. PJM issued the load shed directive to AEP to return the voltage to acceptable levels. AEP shed load at 1114 EPT. At 1237 EPT, the South Princeton capacitor was restored increasing voltages to levels above the load dump rating and the load shed was terminated.

There were demand response resources in the area with base capacity commitment totaling less than 1 MW. The demand response resources were part of the load that was shed by AEP during the event. The settlement treatment of these resources has not yet been finalized.

The Lonesome Pine event, similar to the Twin Branch load shed event, points to the implications of not having locational scarcity pricing. PJM did not have any additional supply to provide voltage support in the Bluefield and Lonesome Pine area, and subsequently had to shed load for reliability, but the LMPs in the area did not reflect the local supply and demand conditions. The Glen Lyn 138 kV bus tripped at 0937 EPT, that created the radial load pocket, the South Bluefield and South Princeton capacitors tripped at 1052 and load was shed between 1114 EPT and 1237 EPT. There was no mechanism to reflect the system conditions in prices during the entire progression of events.

PAIs and Capacity Performance

Both the Twin Branch and Lonesome Pine events triggered Performance Assessment Intervals (PAIs) in very limited locations. Both the events occurred due to the simultaneous planned outages and unplanned outages of transmission facilities including transmission lines, transformers and capacitors. While these events involved shedding load to ensure the contingencies did not have cascading effects on the grid, they are not directly related to capacity shortages to meet load at the zonal, regional or the RTO level. PJM determined that there were no generation or demand resources in either case that could have helped resolve the contingency flow or low voltage issues identified during these events. PJM did not assess nonperformance charges to any resources for these events.

The balancing ratio is theoretically defined as the ratio of actual load and reserve requirements during an emergency event in an area to the total committed capacity in the area. In the case of both these events, if the area is defined as the location where the load was shed, the balancing ratio is undefined because there were no committed resources in the area, other than less than 1.0 MW of demand response. It would not be appropriate or correct to calculate a balancing ratio as a measure of capacity needed during these events by defining a wider area to include committed capacity. It is also not appropriate to use a balancing ratio defined in that way in defining the capacity market offer cap. These events occurred in a very small local area where no capacity resources were held to CP performance requirements. Assessing nonperformance to resources located in the wider area would not be appropriate because their performance would not have helped, and may have even exacerbated the transmission issues identified during these events. These events also do not reflect the type of events that are modeled to define the target installed reserve margin in the capacity market. The MMU recommends that PJM not include the balancing ratios calculated for localized Performance Assessment Intervals (PAIs) in the calculation of the capacity market default offer cap, and only include those events that trigger emergencies at a defined sub-zonal or zonal level.

Real-Time Dispatch and Pricing

The processes to commit and dispatch reserves determine whether PJM implements scarcity pricing. Scarcity pricing transparency requires greater transparency around the processes used to commit and dispatch reserves and to calculate prices.

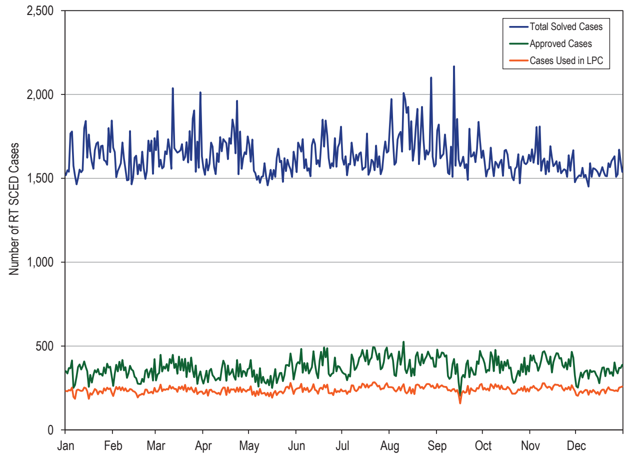
The PJM Real-Time Energy Market consists of a series of applications that produce the generator dispatch for energy and reserves, and five minute locational marginal prices (LMPs). These applications include the ancillary services optimizer (ASO), real-time security constrained economic dispatch (RT SCED), and the locational pricing calculator (LPC).[132] The final real-time LMPs and ancillary service clearing prices are determined for every five minute interval by LPC.

Real-Time SCED and LPC

LPC uses data from an approved RT SCED solution that was used to dispatch the resources in the system. On average, PJM dispatchers approve more than one RT SCED case per five minute interval to send dispatch signals to resources. PJM dispatchers select only a subset of these approved RT SCED cases to be used in LPC to calculate real-time LMPs. It is unclear what criteria dispatchers use for selecting the specific RT SCED cases to be used in LPC for calculating prices for an interval. For example, the case used in LPC often does not apply to the same five minute interval as the five minutes being priced.

Figure 3-65 shows, on a daily basis, the total number of solved RT SCED cases, the number of dispatcher approved RT SCED cases, and the number of RT SCED cases that were used in LPC to calculate five minute LMPs. Table 3-98 shows, on a monthly basis, the number of solved RT SCED cases, the number and percent of solved cases that were approved and the number and percent of solved cases used in LPC, in 2018.

Figure 3-65 Daily RT SCED cases solved, approved and used in pricing: 2018



132 See PJM. "Manual 11: Energy & Ancillary Services Market Operations," Rev. 104 (Feb. 7, 2019)

Table 3-98 RT SCED cases solved, approved and used in pricing: 2018

Month	Number of Solved RT SCED Cases	Number of Approved RT SCED Cases	Number of Approved RT SCED Cases Used in LPC	Approved RT SCED Cases as Percent of Solved Cases	RT SCED Cases Used in LPC as Percent of Solved Cases	RT SCED Cases Used in LPC as Percent of Approved Cases
Jan	50,866	10,725	7,129	21.1%	14.0%	66.5%
Feb	44,709	9,480	6,438	21.2%	14.4%	67.9%
Mar	52,254	11,401	7,486	21.8%	14.3%	65.7%
Apr	50,001	10,103	6,952	20.2%	13.9%	68.9%
May	48,432	10,201	7,036	21.1%	14.5%	69.0%
Jun	49,711	11,634	7,211	23.4%	14.5%	62.0%
Jul	49,919	12,692	7,870	25.4%	15.8%	62.0%
Aug	54,376	12,601	7,743	23.2%	14.2%	61.5%
Sep	49,998	11,288	7,207	22.6%	14.4%	63.9%
Oct	49,106	11,571	7,565	23.6%	15.4%	65.4%
Nov	47,990	12,352	7,618	25.7%	15.9%	61.7%
Dec	47,891	10,487	7,172	21.9%	15.0%	68.5%

Recalculation of Five Minute Real-Time Prices

PJM's five minute interval LMPs are obtained from solved LPC optimization cases. PJM recalculates five minute interval real time LMPs as it believes necessary to correct errors. To do so, PJM reruns LPC optimization cases with modified inputs. The PJM OATT allows for posting of recalculated real time prices no later than 5:00 p.m. of the tenth calendar day following the operating day. The OATT also requires PJM to notify market participants of the underlying error no later than 5:00 pm of the second business day following the operating day.[133] Table 3-99 shows the number of five minute intervals in each month and number of five minute intervals in each month for which PJM recalculated real time prices. In 2018, among 105,120 five minute intervals, PJM recalculated LMPs for 1,828 five minute intervals or 1.74 percent of the total five minute intervals in the year.

Table 3-99 Number of five minute interval real time prices recalculated: 2018

Month	Number of Five Minute Intervals	Number of Five Minute Intervals for which LMPs were recalculated.
January	8,928	153
February	8,064	62
March	8,916	48
April	8,640	44
May	8,928	42
June	8,640	76
July	8,928	148
August	8,928	28
September	8,640	252
October	8,928	107
November	8,652	354
December	8,928	514
Total	105,120	1,828

Real-Time SCED Reserve Shortage

The MMU analyzed the RT SCED solved cases to determine how many of the solved RT SCED cases indicated a shortage of any of the reserve products (synchronized reserve and primary reserve at RTO reserve zone and MAD reserve subzone), how many of these solved cases were approved by PJM, and how many of these were used in LPC to calculate prices. Reserves are considered short if the quantity (MW) of reserves dispatched by RT SCED for a five minute interval was less than the extended reserve requirement. Table 3-100 shows the number and percent of RT SCED cases solved that indicated a shortage of any of the four reserve products (RTO synchronized reserve, RTO primary reserve, MAD synchronized reserve, and MAD primary reserve), the number and percent of the solved RT SCED cases with shortage that were approved by PJM, and the number and percent of the RT SCED cases with

133 OATT Attachment K § 1.10.8(e).

shortage that were used in LPC to calculate real-time prices. Table 3-100 shows that, in 2018, PJM dispatchers approved only five RT SCED cases that indicated a shortage of reserves, from a total of 7,454 solved RT SCED cases that indicated shortage. Among the five approved cases, only three cases were used in LPC to calculate LMPs and reserve clearing prices. It is unclear what criteria PJM dispatchers use to approve the RT SCED cases to send dispatch signals to resources.

Table 3-100 RT SCED cases with reserve shortage: 2018

Month	Number of Solved RT SCED Cases	Number of Solved RT SCED Cases With Reserve Shortage	Number of Approved RT SCED Cases With Reserve Shortage	Number of Approved RT SCED Cases With Reserve Shortage Used in LPC	Cases With Reserve Shortage as Percent of Solved RT SCED Cases	Approved RT SCED Cases With Reserve Shortage as Percent of Solved RT SCED Cases With Shortage	RT SCED Cases With Shortage Used in LPC as Percent of Solved RT SCED Cases With Shortage
Jan	50,866	675	0	0	1.3%	0.0%	0.0%
Feb	44,709	289	0	0	0.6%	0.0%	0.0%
Mar	52,254	752	0	0	1.4%	0.0%	0.0%
Apr	50,001	1,223	0	0	2.4%	0.0%	0.0%
May	48,432	680	0	0	1.4%	0.0%	0.0%
Jun	49,711	249	0	0	0.5%	0.0%	0.0%
Jul	49,919	573	0	0	1.1%	0.0%	0.0%
Aug	54,376	520	2	2	1.0%	0.4%	0.4%
Sep	49,998	523	3	1	1.0%	0.6%	0.2%
Oct	49,106	761	0	0	1.5%	0.0%	0.0%
Nov	47,990	749	0	0	1.6%	0.0%	0.0%
Dec	47,891	460	0	0	1.0%	0.0%	0.0%
Total	595,253	7,454	5	3	1.3%	0.1%	0.0%

While there were 7,454 solved RT SCED cases that indicated shortage, the number of five minute intervals where RT SCED indicated shortage was only 3,776. This is because PJM solves multiple RT SCED cases for each five minute target interval, beginning at approximately 10 to 14 minutes in advance of that interval. RT SCED cases are executed at instances that occur approximately every three minutes, with cases executed more frequently if necessary. Three SCED cases are executed at each instance, with different levels of load bias in each of the three scenarios.[134]

The MMU analyzed the intervals where one or more solved RT SCED cases indicated a shortage of one or more reserve products. Table 3-101 shows, for each month in 2018, the total number of five minute intervals, the number of intervals where at least one solved SCED case showed a shortage of reserves, the number of intervals where more than one solved SCED case showed a shortage of reserves, and the number of five minute intervals where the LPC solution showed a shortage of reserves. Table 3-101 shows that 3,776 intervals, or 3.6 percent of all five minute intervals in 2018 had at least one solved SCED case showing a shortage of reserves, and 1,865 intervals, or 1.8 percent of all five minute intervals in 2018 had more than one solved SCED case showing a shortage of reserves.

Table 3-101 Five minute intervals with shortage: 2018

Month	Number of Five Minute Intervals	Number of Intervals With At Least One Solved SCED Case Short of Reserves	Percent Intervals With At Least One Solved SCED Case Short of Reserves	Number of Intervals With Multiple Solved SCED Cases Short of Reserves	Percent Intervals With Multiple Solved SCED Cases Short of Reserves	Number of Intervals With Five Minute Shortage Prices in LPC	Percent Intervals With Five Minute Shortage Prices in LPC
Jan	8,928	300	3.4%	174	1.9%	0	0.0%
Feb	8,064	150	1.9%	73	0.9%	0	0.0%
Mar	8,916	358	4.0%	174	2.0%	0	0.0%
Apr	8,640	597	6.9%	290	3.4%	0	0.0%
May	8,928	354	4.0%	166	1.9%	0	0.0%
Jun	8,640	128	1.5%	65	0.8%	0	0.0%
Jul	8,928	285	3.2%	152	1.7%	0	0.0%
Aug	8,928	262	2.9%	133	1.5%	2	0.0%
Sep	8,640	292	3.4%	141	1.6%	1	0.0%
Oct	8,928	405	4.5%	184	2.1%	0	0.0%
Nov	8,652	393	4.5%	199	2.3%	0	0.0%
Dec	8,928	252	2.8%	114	1.3%	0	0.0%
Total	105,120	3,776	3.6%	1,865	1.8%	3	0.0%

134 A case is executed when it begins to solve. Most but not all cases are solved. SCED cases take about one to two minutes to solve.

While a single SCED case indicating a shortage for a target interval among multiple SCED cases that solved for that interval could be the result of erroneous inputs, it is less likely that an interval with multiple RT SCED cases indicating shortage was the result of an error. There were 3 five minute intervals with shortage pricing that occurred on two days in 2018, while there were 1,865 five minute intervals where multiple solved SCED cases showed a shortage of reserves. The data indicates reluctance on the part of PJM operators to approve SCED cases with a shortage, and reluctance to use the SCED cases with a shortage for calculating five minute prices in LPC.

The PJM Real-Time Energy Market produces an efficient outcome only when prices are allowed to reflect the fundamental supply and demand conditions in the market in real time. While it is appropriate for operators to ensure that cases that use erroneous inputs are not approved and not allowed to set prices, it is essential that operator discretion not extend beyond what is necessary and that operator discretion not prevent shortage pricing when there are shortage conditions. This is a critical issue now that PJM settles all real-time energy transactions on a five minute basis using the prices calculated by LPC. The 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.

Scarcity and Scarcity Pricing

In electricity markets, scarcity means that demand, including reserve requirements, is nearing the limits of the currently available capacity of the system. Under the PJM rules that were in place through September 30, 2012, high prices, or scarcity pricing, resulted from high offers by individual generation owners for specific units when the system was close to its available capacity. But this was not an efficient way to manage scarcity pricing and made it difficult to distinguish between market power and scarcity pricing. PJM refers to scarcity pricing as shortage pricing. The terms are used interchangeably here.

On October 1, 2012, PJM introduced a new administrative scarcity pricing regime. Under these market rules, shortage pricing conditions are triggered when there is a shortage of synchronized or primary reserves in the RTO or in the Mid-Atlantic and Dominion (MAD) Subzone. In times of reserve shortage, the value of reserves is included as a penalty factor in the optimization and in the price of energy.[135] Shortage pricing is also triggered when PJM issues a voltage reduction action or a manual load dump action for a reserve zone or a reserve subzone. When shortage pricing is triggered, the reserve penalty factors are incorporated in the calculation of the market clearing prices for the reserve that is short. The market clearing prices for reserves during reserve shortages in real time were determined based on vertical demand curves for synchronized and primary reserves, defined for the Mid-Atlantic Region and for the entire RTO, called the Operating Reserve Demand Curves (ORDC). The penalty factors for the reserve products in the ORDC started at $250 per MWh for the 2012/2013 Delivery Year and gradually increased to $850 per MWh for the 2015/2016 Delivery Year.

In 2015, PJM revised the rules to add a conditional second step to the operating reserve demand curves, that is only in effect during hot weather alerts, cold weather alerts and other emergency conditions, to allow PJM to procure additional reserves at a lower clearing price of $300 per MWh.[136] When there are no emergency conditions in place, the ORDC remains a single-step curve.

On May 11, 2017, PJM made revisions to the triggers for shortage pricing and implemented five minute shortage pricing in response to Order No. 825. These revisions did not change the operating reserve demand curves.

On July 12, 2017, PJM implemented updates to the Operating Reserve Demand Curves that determine the value of the penalty factors that are incorporated in the calculation of the synchronized and primary reserve market clearing prices and the locational marginal price for energy. PJM added an extended reserve requirement to the operating reserve demand curves. The extended synchronized reserve requirement is defined as the synchronized reserve requirement plus 190 MW. The extended primary reserve requirement is defined as the primary reserve requirement plus 190 MW. PJM retains the ability to add a conditional extended reserve requirement during hot weather alerts, cold weather

135 See PJM Operating Agreement Schedule 1 § 2.2(d).
136 151 FERC ¶ 61,017 (2015).

alerts or other emergencies that would increase the extended reserve requirement beyond 190 MW.

In 2018, there were three five minute intervals with shortage pricing that occurred on two days in PJM.

Final Rule on Shortage Pricing and Settlement Intervals (Order No. 825)

On September 17, 2015, the Commission issued a Notice of Proposed Rulemaking (NOPR) in which the Commission proposed to address price formation issues in RTOs/ISOs ("price formation NOPR").[137] In particular, the price formation NOPR proposed (i) to require the alignment of settlement and dispatch intervals for energy and operating reserves; and (ii) to require that each RTO/ISO trigger shortage pricing for any dispatch interval during which a shortage of energy or operating reserves occurs. These proposed reforms are intended to ensure that resources have price signals that provide incentives to conform their output to dispatch instructions, and that prices reflect operating needs at each dispatch interval.[138]

The Commission required each RTO/ISO to trigger shortage pricing for any dispatch and pricing interval in which a shortage of energy or operating reserves is indicated by the RTO/ISO's software.[139] As of May 11, 2017, the rule requires PJM to trigger shortage pricing for any five minute interval for which the Real-Time SCED (Security Constrained Economic Dispatch) indicates a shortage of synchronized reserves or primary reserves. Prior to May 11, 2017, if the dispatch tools (Intermediate-Term and Real-Time SCED) reflect a shortage of reserves (primary or synchronized) for a time period shorter than a defined threshold (30 minutes) due to ramp limitations or unit startup delays, it was considered a transient shortage, a shortage event was not declared, and shortage pricing was not implemented. Both Real-Time SCED and Intermediate-Term SCED had to consistently identify that a shortage of a particular reserve product existed for a period of at least 30 minutes to trigger the shortage pricing penalty factor for that reserve product. For example, if Real-Time SCED indicated a shortage of RTO wide primary reserve for an interval but the Intermediate-Term SCED forecasts that the reserve shortage did not extend beyond its first look ahead interval (15 minutes ahead of the Real-Time SCED Interval), it was considered a transient shortage, and shortage pricing was not implemented. If Real-Time SCED indicated a shortage of RTO wide primary reserve for an interval and the Intermediate-Term SCED forecasts that the reserve shortage extended for at least two look ahead intervals (30 minutes ahead of the Real-Time SCED Interval), shortage pricing was implemented.

The rationale for including voltage reduction actions and manual load dump actions as triggers for shortage pricing is to reflect the fact that when operators need to take these emergency actions to maintain reliability, the system is short reserves and prices should reflect that condition, even if the data does not show a shortage of reserves.[140]

PJM Compliance Filing on Shortage Pricing

On January 11, 2017, PJM filed proposed tariff revisions to comply with Order No. 825 and requested a simultaneous implementation date of February 1, 2018, for the settlement interval reforms and shortage pricing reforms.[141] In the January 11th Compliance Filing, PJM proposed to implement shortage pricing through the inclusion of the Reserve Penalty Factors in real-time LMPs when the real-time security constrained economic dispatch software determines that a primary reserve or synchronized reserve shortage exists on a five minute basis.

On February 1, 2017, the MMU filed comments generally supporting the January 11th Compliance Filing but seeking a number of refinements.[142] The MMU recommended that: (i) the PJM rules require that dispatchable resources have five minute meters so that there can be accurate five minute settlements; (ii) the rules clarify the settlement interval applicable to withdrawals by generators; (iii) the exemption of DR from the five minute settlements requirement be removed; (iv) the rules consistently provide for division by 12; (v) that the rules include a precise mathematical formulation of deviation charges with clear definitions of withdrawals and injections, units of measurement,

137 152 FERC ¶ 61,218 (2015).
138 *Id* at P 5.
139 *Id* at P 162.

140 *See, e.g.*, Scarcity and Shortage Pricing, Offer Mitigation and Offer Caps Workshop, Docket No. AD14-14-000, Transcript 29:21–30:14 (Oct. 28, 2014).
141 *See PJM Interconnection LLC*, Order No. 825 Compliance Filing, Docket No. ER17-775 (January 11, 2017) ("January 11th Compliance Filing").
142 Comments of the Independent Market Monitor for PJM, Docket No. ER17-775.

and time periods; and (vi) that the rules require PJM to document biasing practices that affect market outcomes, as used in SCED (Security Constrained Economic Dispatch) and ASO (Ancillary Services Optimizer) and to report its application of biasing.[143]

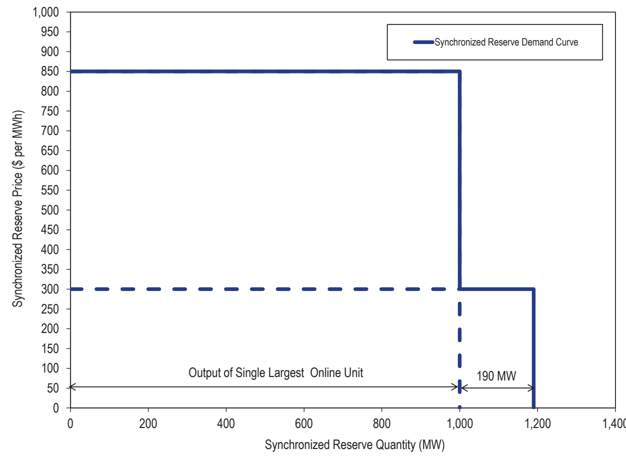
On May 11, 2017, PJM implemented five minute shortage pricing. From May 11 through December 31, 2017, there were 21 intervals when five minute shortage pricing was triggered, all on the same day, September 21, 2017. There were 3 five minute intervals with shortage pricing that occurred on two days in 2018.

PJM Tariff Revisions to Operating Reserve Demand Curves

On May 12, 2017, PJM submitted tariff revisions to reflect changes to the Operating Reserve Demand Curves (ORDC) used in the Real-Time Energy Market to price shortage of primary reserves and synchronized reserves.[144] The updates to the ORDC went into effect on July 12, 2017.

PJM revised the synchronized reserve requirement in a reserve zone or a subzone from the economic maximum of the largest unit on the system to 100 percent of the actual output of the single largest online unit in that reserve zone or subzone. PJM revised the primary reserve requirement in a reserve zone or a subzone from 150 percent of the economic maximum of the largest unit on the system to 150 percent of the actual output of the single largest online unit in that reserve zone or subzone. The first step of the demand curves for primary and synchronized reserves are set at the primary and synchronized reserve requirement. Since the primary and synchronized reserve requirements are based on the actual output of the largest resource, the MW value of the first step changes in real time based on the real-time dispatch solution. The first step continues to be priced at $850 per MWh. PJM also added a permanent second step to the primary and synchronized reserve demand curves, set at the extended primary and synchronized reserve requirements. The extended primary and synchronized reserve requirements are defined as the primary and synchronized reserve requirements, plus 190 MW. This 190 MW second step is priced at $300 per MWh. Figure 3-66 shows an example of the updated synchronized reserve demand curve when the output of the single largest unit in the region equals 1,000 MW.

Figure 3-66 Updated synchronized reserve demand curve showing the permanent second step



Scarcity Pricing and Energy Price Formation

The current operating reserve demand curves (ORDC) in PJM define and administrative price for estimated reserves (primary and synchronized reserves) up to the extended reserve requirement quantities. The demand curve shown in Figure 3-66 drops to a zero price for quantities above the extended reserve requirement. The price for reserve quantities less than the reserve requirement is $850 per MWh, and the price for reserve quantities above the reserve requirement to 190 MW above the reserve requirement is $300 per MWh. The price below the reserve requirement should be sufficient to cover the marginal cost of any generator on the system capable of responding.

Unlike an energy only market, PJM does not set scarcity prices to compensate the full fixed and avoidable cost of the resources needed to meet peak demand. The PJM market compensates resources with a capacity market obligation for availability to the system when they are needed to meet demand. In addition, because consumers do not respond in the short run to real-time energy market prices, scarcity pricing cannot ration scarce energy among consumers according to their marginal willingness to pay. By extension, PJM cannot measure consumers' willingness to pay for reserves to avoid a loss of load. Therefore, the ORDC appropriately does not attempt to administratively represent consumers'

143 *Id.*
144 See PJM Filing, FERC Docket No. ER17-1590-000 (May 12, 2017).

willingness to pay for reserves, or customers' value of lost load.

Locational Reserve Requirements

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

The current operating reserve demand curves are modeled for reserve requirements for the RTO level (RTO reserve zone) and for the Mid-Atlantic and Dominion region (MAD Subzone). This was a result of historical congestion patterns where limits to transmission capacity to deliver power from outside the MAD Subzone into the MAD Subzone necessitated maintaining reserves in the MAD area to respond to disturbances within the subzone. However, in real-time operations, due to generator outages, transmission outages, and local weather patterns, PJM may need to maintain or operate resources in other local areas to maintain local reliability, in addition to the RTO and MAD reserve levels. Currently, these units are committed out of market for reliability reasons, or are modeled as artificial closed loop interfaces with limited deliverability modeled inside the closed loop from resources located outside. The value of operating these resources, including generators that are manually committed for reliability and demand resources that may be dispatched inside a closed loop, is not reflected in prices. A more efficient way to reflect these requirements would be to have locational reserve requirements that are adjusted based on PJM forecasts and reliability studies.

Operator Actions

Actions taken by PJM operators to maintain reliability, such as committing more reserves than required, may suppress reserves prices. The need to commit more reserves could instead be reflected in the ORDC, allowing the market to efficiently account for the reliability commitment in the energy and reserves markets.

Shortage Pricing Intervals in 2018

In 2018, there were three intervals with five minute shortage pricing in PJM. Two of the intervals were on August 31, and one interval was on September 30. In all three intervals, shortage pricing was triggered due to synchronized reserves being short of the extended synchronized reserve requirement but greater than the reliability synchronized reserve requirement.[145] There were no five minute intervals with primary reserve shortage in 2018. Table 3-102 shows the extended synchronized reserve requirement, the total synchronized reserves, the synchronized reserve shortage, and the synchronized reserve clearing prices for the RTO reserve zone during the three intervals with shortage pricing. Table 3-103 shows the extended synchronized reserve requirement, the total synchronized reserves, the synchronized reserve shortage, and the synchronized reserve clearing prices for the MAD reserve subzone during the three intervals with shortage pricing. In all three intervals, the amount of synchronized reserve shortage is less than 190 MW, the quantity of the second step in the operating reserve demand curves.

PJM enforces the RTO wide reserve requirement and supplemental reserve requirement for the MAD region. The MAD reserve subzone is nested within the RTO reserve zone. Resources located in the MAD reserve subzone can simultaneously satisfy the synchronized reserve requirement of the RTO reserve zone and the synchronized reserve requirement of the MAD reserve subzone. Resources located outside the MAD reserve subzone can satisfy the synchronized reserve requirement of the RTO reserve zone, and subject to transfer limits defined by transmission constraints, satisfy the reserve requirement of the MAD subzone. The synchronized reserve clearing price of the RTO reserve zone is set by the shadow price of the binding reserve requirement constraint of the RTO reserve zone.[146] The synchronized reserve clearing price of the MAD reserve subzone, nested within the RTO reserve zone, is set by the sum of the shadow prices of the binding reserve requirement constraint of the RTO reserve zone and the shadow price of the binding reserve requirement constraint of the MAD reserve subzone.

In all three intervals in 2018 with shortage pricing, both the RTO zone and the MAD subzone cleared with synchronized reserves less than their extended requirement. The shadow price of the synchronized

145 The extended synchronized reserve requirement is defined as the reliability synchronized reserve requirement plus 190 MW.

146 If the reserve requirement cannot be met by the resources located within the reserve zone, the shadow price of the reserve requirement is set the applicable operating reserve demand curve.

reserve requirement of the RTO reserve zone was $300 per MWh. The shadow price of the synchronized reserve requirement of the MAD reserve zone was also $300 per MWh. The clearing price for synchronized reserves in the MAD subzone was $600 per MWh, the sum of the shadow prices of the synchronized reserve constraints for the RTO zone and MAD subzone.

Table 3-102 RTO Synchronized Reserve Shortage Intervals: 2018

Interval (EPT)	RTO Extended Synchronized Reserve Requirement (MW)	Total RTO Synchronized Reserves (MW)	RTO Synchronized Reserve Shortage (MW)	RTO Synchronized Reserve Clearing Price ($/MWh)
31-Aug-18 09:35	1,554.5	1,552.5	2.0	$300
31-Aug-18 09:40	1,556.9	1,417.3	139.6	$300
30-Sep-18 11:35	1,571.4	1,502.1	69.3	$300

Table 3-103 MAD Synchronized Reserve Shortage Intervals: 2018

Interval (EPT)	MAD Extended Synchronized Reserve Requirement (MW)	Total MAD Synchronized Reserves (MW)	MAD Synchronized Reserve Shortage (MW)	MAD Synchronized Reserve Clearing Price ($/MWh)
31-Aug-18 09:35	1,554.5	1,552.5	2.0	$600
31-Aug-18 09:40	1,556.9	1,417.3	139.6	$600
30-Sep-18 11:35	1,571.4	1,502.1	69.3	$600

The synchronized reserve shortage that occurred on September 30, 2018, was the result of a unit trip. The shortage coincided with a synchronized reserve event that began at 1129 EPT and ended at 1140 EPT, in response to the unit trip.

Accuracy of Reserve Measurement

The definition of a shortage of synchronized and primary reserves is based on the measured and estimated levels of load, generation, interchange, demand response, and reserves from the real-time SCED software. The definition of such shortage also includes discretionary operator inputs to the ASO (Ancillary Service Optimizer) or SCED software. For shortage pricing to be accurate, there must be accurate measurement of real-time reserves. That does not appear to be the case at present in PJM, but there does not appear to be any reason that PJM cannot accurately measure reserves. Without accurate measurement of reserves on a minute by minute basis, system operators cannot know with certainty that there is a shortage condition and a reliable trigger for five minute shortage pricing does not exist. The benefits of five minute shortage pricing are based on the assumption that a shortage can be precisely and transparently defined.[147]

The Commission directed in the Final Rule that, to the extent an RTO/ISO needs to enhance its measurement capabilities to implement the shortage pricing requirement, it should propose to do so in its compliance filing.[148] PJM did not propose any enhancements to reserve measurement in the January 11th compliance filing.

In the period between May 11, 2017, and December 31, 2017, there were instances when the real-time reserve data on the PJM website showed a shortage of synchronized reserves but there was not shortage pricing. The real-time reserves on the PJM website were operational reserves as measured by Energy Management System (EMS), and not the reserves dispatched and priced by SCED.[149] RT SCED estimated reserves based on generation dispatch with a 15 minute look ahead until July 16, 2017. On July 17, PJM reduced the RT SCED look-ahead from 15 minutes to 10 minutes, but the reserve levels used to define shortage pricing continue to be look-ahead estimates and not real-time operational reserves. As a result, PJM's scarcity pricing does not reflect actual current scarcity conditions, but reflects the expected response of generation and forecast load 10 minutes in the future.[150]

The accuracy of reserve measurement in PJM can be evaluated using historical data on performance during spinning events. The level of tier 1 biasing also reflects PJM dispatchers' estimate of the error in the measurement of tier 1 synchronized reserve and the goal of adding additional reserves.

Historical Performance During Spinning Events

All resources that respond to spinning events are paid for their response. Table 3-104 shows the performance of

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

148 155 FERC ¶ 61,276 at P 177 (2016).

149 PJM has since added the real-time SCED dispatched reserve quantities, in addition to the operational reserve quantities to its website.

150 Prior to July 17, 2017, PJM's scarcity pricing reflected the expected response of generation and load fifteen minutes in the future.

tier 1 and tier 2 synchronized reserves during spinning events declared in 2015, 2016, 2017, and 2018 that lasted at least 10 minutes. In 2015, tier 1 response MW were measured as the increase in MW from all resources as a response to the spinning event declaration, regardless of whether the units were part of the tier 1 MW estimate. As a result, the 2015 estimates for tier 1 response were greater than 100 percent.

Beginning in 2016, PJM reported the response to spinning events only from the units that were part of its tier 1 estimate. In 2016, the tier 1 response rate was never greater than 85 percent, with an average response rate of 75 percent. In 2017, the tier 1 response rate was never greater than 75 percent, with an average response rate of 60 percent. In 2018, the tier 1 response rate was never greater than 90 percent, with an average response rate of 66 percent during the seven spinning events that lasted for at least 10 minutes.

PJM's current approach to estimating tier 1 reserves is not an accurate basis for defining shortage and reflects, to an unknown degree, the goal of adding additional reserves above the defined target level.

Tier 1 Synchronized Reserve Estimate Bias

Tier 1 synchronized reserves are calculated based on unit capabilities but are also subject to tier 1 estimate bias by PJM. PJM manually modifies (increasing or decreasing) the tier 1 synchronized reserve estimate of the market solution, forcing more or less tier 2 synchronized reserve and nonsynchronized reserve to clear to meet reserve requirements. Tier 1 biasing reflects the operators' view of the available tier 1 MW and operators' goal of adding additional reserves above the defined target level. Table 10-15 shows the average monthly biasing of tier 1 estimates in the Ancillary Service Optimizer (ASO) in 2017 and 2018.

There are no rules in the PJM tariff or manuals regarding the use of tier 1 MW biasing. With five minute shortage pricing and the associated market impacts, there is a clear need for explicit rules governing operator discretion to calculated reserves. The MMU has recommended since 2012 that PJM explicitly define the rules for using tier 1 biasing.

Table 3-104 Performance of synchronized reserves during spinning events: 2015 through 2018

Spin Event (Date, Hour)	Duration (Minutes)	Tier 1 Estimate MW (Adjusted by DGP)	Tier 1 Response MW	Tier 2 Scheduled MW	Tier 2 Response MW	Tier 1 Response Percent	Tier 2 Response Percent
Mar 3, 2015 12	11	1,079.0	1,365.1	484.4	272.3	126.5%	56.2%
Mar 16, 2015 06	24	541.5	576.4	248.0	180.2	106.4%	72.7%
Mar 17, 2015 19	17	1,428.9	1,693.1	247.2	232.8	118.5%	94.2%
Mar 23, 2015 19	15	851.3	1,420.0	273.5	205.8	166.8%	75.2%
Jul 30, 2015 10	10	1,458.4	2,145.7	79.7	24.0	147.1%	30.1%
Jan 18, 2016 17	12	861.0	733.5	616.7	508.8	85.2%	82.5%
Feb 8, 2016 15	10	1,750.2	1,338.2	228.4	200.1	76.5%	87.6%
Apr 14, 2016 20	10	1,182.8	1,000.6	346.3	304.8	84.6%	88.0%
Jul 28, 2016 13	15	649.4	500.4	822.9	655.8	77.1%	79.7%
Nov 4, 2016 17	11	744.5	497.1	758.0	709.2	66.8%	93.6%
Dec 31, 2016 05	12	971.2	585.0	594.4	485.7	60.2%	81.7%
Mar 23, 2017 06	24	926.8	566.7	742.8	559.1	61.1%	75.3%
Apr 08, 2017 11	10	1,222.6	827.2	879.3	828.7	67.7%	94.2%
May 08, 2017 04	10	1,325.6	976.3	335.1	298.5	73.6%	89.1%
Jun 08, 2017 03	10	974.4	726.7	575.7	522.4	74.6%	90.7%
Sep 04, 2017 20	15	476.3	68.1	601.0	563.8	14.3%	93.8%
Sep 21, 2017 14	16	305.8	217.4	1,253.9	1,037.3	71.1%	82.7%
Jan 03, 2018 03	13	1,896.7	509.9	112.6	57.6	26.9%	51.2%
Apr 12, 2018 17	10	1,063.3	591.2	464.6	372.5	55.6%	80.2%
Jun 30, 2018 09	11	2,710.1	2,086.2	71.6	56.8	77.0%	79.3%
Jul 10, 2018 15	12	784.3	524.9	494.6	308.8	66.9%	62.4%
Aug 12, 2018 11	11	1,824.5	1,390.4	274.5	229.8	76.2%	83.7%
Sep 30, 2018 11	11	1,430.9	976.4	231.2	216.9	68.2%	93.8%
Oct 30, 2018 06	11	239.7	215.9	607.7	431.5	90.1%	71.0%

Generator Data used for Reserve Estimates

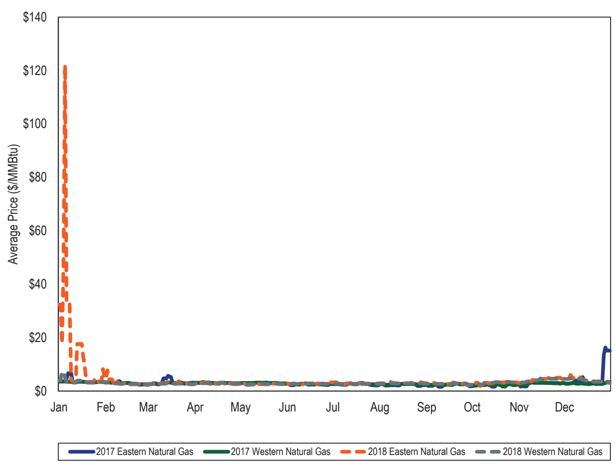
A potential source of error in calculating tier 1 MW is the use of the economic dispatch point to calculate the available ramp limited MW in 10 minutes rather than the actual output from the generator for any five minute interval. PJM addressed this issue partially in 2015 by adjusting a resource's available 10 minute ramp with Degree of Generator Performance metric (DGP).

PJM Cold Weather Operations 2018

Natural Gas Supply and Prices

As of December 31, 2018, gas fired generation was 40.2 percent (74,716.8 MW) of the total installed PJM capacity (185,951.7 MW).[151] Figure 3-67 shows the average daily price of delivered natural gas for eastern and western parts of PJM service territory in 2018 and 2017.[152]

Figure 3-67 Average daily delivered price for natural gas: 2017 and 2018 ($/MMBtu)



During 2018, a number of interstate gas pipelines that supply fuel for generators in the PJM service territory issued restriction notices limiting the availability of nonfirm transportation services. These notices include warnings of operational flow orders (OFO) and actual OFOs. These notices may, depending on the nature of the transportation service purchased, permit the pipelines to restrict the provision of gas to 24 hour ratable takes which means that hourly nominations must be the same for each of the 24 hours in the gas day, with penalties for deviating from the nominated quantities. Pipelines may also enforce strict balancing constraints which limit the ability of gas users, depending on the nature of the transportation service purchased, to deviate from the 24 hour ratable take and which may limit the ability of users to have access to unused gas.

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

151 *2018 State of the Market Report for PJM*, Section 5: Capacity Market, at Installed Capacity.

152 Eastern natural gas consists of the average of Texas Eastern M3, Transco Zone 6 non-NY, Transco Zone 6 NY and Transco Zone 5 daily fuel price indices. Western natural gas prices are the average of Dominion North Point, Columbia Appalachia and Chicago City gate daily fuel price indices.

Energy Uplift (Operating Reserves)

Energy uplift is paid to market participants under specified conditions in order to ensure that competitive energy and ancillary service market outcomes do not require efficient resources to operate for the PJM system at a loss.[1] Referred to in PJM as operating reserve credits, lost opportunity cost credits, reactive services credits, synchronous condensing credits or black start services credits, these uplift payments are intended to be one of the incentives to generation owners to offer their energy to the PJM energy market for dispatch based on short run marginal costs and to operate their units as directed by PJM dispatchers. These credits are paid by PJM market participants as operating reserve charges, reactive services charges, synchronous condensing charges or black start services charges.

Uplift is an inherent part of the PJM market design. Part of that uplift is the result of the nonconvexity of power production costs. Uplift payments cannot be eliminated, but uplift payments should be limited to the efficient level. In wholesale power market design, a choice must be made between efficient prices and prices that fully compensate costs. Economists recognize that no single price achieves both goals in markets with nonconvex production costs, like the costs of producing electric power.[2] [3] In wholesale power markets like PJM, efficient prices equal the short run marginal cost of production by location. The dispatch of generators based on these efficient price signals minimizes the total market cost of production. For generators with nonconvex costs, marginal cost prices may not cover the total cost of starting the generator and running at the efficient output level. Uplift payments cover the difference. The PJM market design incorporates efficient prices with minimal uplift payments. There are improvements to the market design and uplift rules that could further reduce uplift payments while maintaining efficient prices.

1 Loss exists when gross energy and ancillary services market revenues are less than short run marginal costs, including all elements of the energy offer, which are startup, no load and incremental offers.

2 *See* Stoft, *Power System Economics: Designing Markets for Electricity*, New York: Wiley (2002) at 272; Mas-Colell, Whinston, and Green, *Microeconomic Theory*, New York: Oxford University Press (1995) at 570; and Quinzii, *Increasing Returns and Efficiency*, New York: Oxford University Press (1992).

3 The production of output is convex if the production function has constant or decreasing returns to scale, which result in constant or rising average costs with increases in output. Production is nonconvex with increasing returns to scale, which is the case when generating units have start or no load costs that are large relative to marginal costs. *See* Mas-Colell, Whinston, and Green at 132.

In PJM, all energy payments to demand response resources are uplift payments. The energy payments to these resources are not part of the supply and demand balance, they are not paid by LMP revenues and therefore the energy payments to demand response resources have to be paid as out of market uplift. The energy payments to economic DR are funded by real-time load and real-time exports. The energy payments to emergency DR are funded by participants with net energy purchases in the Real-Time Energy Market. The current payment structure for DR is an inefficient element of the PJM market design.[4]

Overview

Energy Uplift Credits

- **Types of credits.** In 2018, energy uplift credits were $199.0 million, including $34.0 million in day-ahead generator credits, $90.2 million in balancing generator credits, $52.3 million in lost opportunity cost credits, $13.2 million in reactive credits, and $8.6 million in local constraint control credits.
- **Types of units.** Coal units received 61.3 percent of all day-ahead generator credits and 88.0 percent of all reactive service credits. Combustion turbines received 76.4 percent of all balancing generator credits and 71.9 percent of lost opportunity cost credits.
- **Economic and Noneconomic Generation.** In 2018, 84.6 percent of the day-ahead generation eligible for operating reserve credits was economic and 68.9 percent of the real-time generation eligible for operating reserve credits was economic.
- **Day-Ahead Unit Commitment for Reliability.** In 2018, 1.3 percent of the total day-ahead generation MWh was scheduled as must run by PJM, of which 47.3 percent received energy uplift payments.
- **Concentration of Energy Uplift Credits.** The top 10 units receiving energy uplift credits received 21.2 percent of all credits. The top 10 organizations received 74.6 percent of all credits. The HHI for day-ahead operating reserves was 8013, the HHI for balancing operating reserves was 2865 and the HHI for lost opportunity cost was 4860, all of which are classified as highly concentrated.

4 Demand Response payments are addressed in Section 6: Demand Response.

- **Lost Opportunity Cost Credits.** Lost opportunity cost credits increased by $37.7 million or 258.6 percent, in 2018 compared to 2017, from $14.6 million to $52.3 million. This increase was the result of combustion turbines and diesels scheduled day-ahead and not requested in real time. This increase was also a result of backing down steam and combined cycle units in order to control for the west to east transfer interfaces binding in January. Generation from combustion turbines and diesels scheduled day-ahead but not requested in real time receiving lost opportunity cost credits increased by 374 GWh or 58.6 percent in 2018, compared to 2017, from 639 GWh to 1,013 GWh.

Energy Uplift Charges

- **Energy Uplift Charges.** Total energy uplift charges increased by $72.0 million, or 56.5 percent, in 2018 compared to 2017, from $127.3 million to $199.3 million.
- **Energy Uplift Charges Categories.** The increase of $72.0 million in 2018 is comprised of a $9.2 million increase in day-ahead operating reserve charges, a $69.9 million increase in balancing operating reserve charges and a $7.3 million decrease in reactive services charges.
- **Average Effective Operating Reserve Rates in the Eastern Region.** Day-ahead load paid $0.041 per MWh, real-time load paid $0.029 per MWh, a DEC paid $0.722 per MWh and an INC and any load, generation or interchange transaction deviation paid $0.681 per MWh.
- **Average Effective Operating Reserve Rates in the Western Region.** Day-ahead load paid $0.041 per MWh, real-time load paid $0.027 per MWh, a DEC paid $0.735 per MWh and an INC and any load, generation or interchange transaction deviation paid $0.693 per MWh.
- **Reactive Services Rates.** The ComEd, Pepco, and EKPC control zones had the three highest local voltage support rates: $0.116, $0.023 and $0.015 per MWh.

Geography of Charges and Credits

- In 2018, 88.2 percent of all uplift charges allocated regionally (day-ahead operating reserves and balancing operating reserves) were paid by transactions at control zones, 2.9 percent by transactions at hubs and aggregates, and 8.9 percent by transactions at interchange interfaces.
- Generators in the Eastern Region received 47.7 percent of all balancing generator credits, including lost opportunity cost and canceled resources credits.
- Generators in the Western Region received 50.7 percent of all balancing generator credits, including lost opportunity cost and canceled resources credits.
- External generators received 1.6 percent of all balancing generator credits, including lost opportunity cost and canceled resources credits.

Recommendations

- The MMU recommends that uplift be paid only based on operating parameters that reflect the flexibility of the benchmark new entrant unit (CONE unit) in the PJM Capacity Market. (Priority: High. First reported Q1, 2018. Status: Not adopted.)
- 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. (Priority: Medium. First reported 2013. Status: Not adopted.)
- 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. (Priority: Medium. First reported 2015. Status: Not adopted.)
- 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. (Priority: Medium. First Reported 2016. Status: Not adopted.)
- 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. (Priority: Medium. First Reported 2012. Status: Not adopted.)

- The MMU recommends eliminating intraday segments from the calculation of uplift payments and returning to calculating the need for uplift based on the entire 24 hour operating day. (Priority: High. First reported Q1, 2018. Status: Not adopted.)
- The MMU recommends the elimination of 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. (Priority: Medium. First reported 2013. Status: Not adopted.)
- The MMU recommends enhancing the current energy uplift allocation rules to reflect the recommended elimination of day-ahead operating reserves, the timing of commitment decisions and the commitment reasons. (Priority: High. First reported 2012. Status: Not adopted.)
- The MMU recommends reincorporating the use of net regulation revenues as an offset in the calculation of balancing operating reserve credits. (Priority: Medium. First reported 2009. Status: Not adopted. Stakeholder process.)
- 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. (Priority: Low. First reported 2013. Status: Not adopted. Stakeholder process.)
- The MMU recommends three modifications to the energy lost opportunity cost calculations:
  - The MMU recommends calculating LOC based on 24 hour daily periods for combustion turbines and diesels scheduled in the Day-Ahead Energy Market, but not committed in real time. (Priority: Medium. First reported 2014. Status: Not adopted.)
  - The MMU recommends that units scheduled in the Day-Ahead Energy Market and not committed in real time should be compensated for LOC based on their real-time desired and achievable output, not their scheduled day-ahead output. (Priority: Medium. First reported 2015. Status: Not adopted.)
  - The MMU recommends that only flexible fast start units (startup plus notification times of 10 minutes or less) and short minimum run times (one hour or less) be eligible by default for the LOC compensation to units scheduled in the Day-Ahead Energy Market and not committed in real time. Other units should be eligible for LOC compensation only if PJM explicitly cancels their day-ahead commitment. (Priority: Medium. First reported 2015. Status: Not adopted.)
- The MMU recommends that up to congestion transactions be required to pay energy uplift charges for both the injection and the withdrawal sides of the UTC. (Priority: High. First reported 2011. Status: Not adopted.)
- The MMU recommends eliminating the use of internal bilateral transactions (IBTs) in the calculation of deviations used to allocate balancing operating reserve charges. (Priority: High. First reported 2013. Status: Adopted 2018.[5])
- 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. (Priority: Medium. First reported 2014. Status: Not adopted. Stakeholder process.)
- The MMU recommends that the total cost of providing reactive support be categorized and allocated as reactive services. Reactive services credits should be calculated consistent with the balancing operating reserve credit calculation. (Priority: Medium. First reported 2012. Status: Not adopted. Stakeholder process.)
- The MMU recommends including real-time exports and real-time wheels in the allocation of the cost of providing reactive support to the 500 kV system or above, in addition to real-time load. (Priority: Low. First reported 2013. Status: Not adopted.)
- The MMU recommends modifications to the calculation of lost opportunity costs credits paid to wind units. The lost opportunity costs credits paid to wind units should be based on the lesser of the

5 As of November 1, 2018, internal bilateral transactions are no longer used for the calculation of deviations for purposes of allocating balancing operating reserve charges. See the *2018 State of the Market Report for PJM*, Section 3: "Energy Market" at "Internal Bilateral Transactions" for an analysis of the impact of this change on virtual bidding activity.

desired output, the estimated output based on actual wind conditions and the capacity interconnection rights (CIRs). The MMU recommends that PJM allow wind units to request CIRs that reflect the maximum output wind units want to inject into the transmission system at any time. (Priority: Low. First reported 2012. Status: Not adopted.)

- 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 the Manual 11 attachment C procedure with the implementation of hourly offers (ER16-372-000). (Priority: Medium. First reported 2016. Status: Not adopted.[6])
- 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. (Priority: Medium. First reported 2011. Status: Partially adopted.)
- 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. (Priority: High. First reported 2013. Status: Partially adopted.[7])
- The MMU recommends that PJM pay uplift based on the offer at the lower of the actual unit output or the dispatch signal MW. (Priority: Medium. First reported Q1, 2018. Status: Not adopted.)
- 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. (Priority: Medium. First reported Q1, 2018. Status: Not adopted.)
- 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 (Priority: Medium. New recommendation. Status: Not adopted.)

Conclusion

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

It is not appropriate to accept that inflexible units should be paid or set price based on short run marginal costs plus no load. The question of why units make inflexible offers should be addressed directly. Are units inflexible because they are old and inefficient, because owners have not invested in increased flexibility or because they serve as a mechanism for the exercise of market power? The question of why the inflexible unit was built, whether it was built under cost of service regulation and whether it is efficient to retain the unit should be answered directly. The question of how to provide market incentives for investment in flexible units and for investment in increased flexibility of existing units should be addressed directly. The question of whether inflexible units should be paid uplift at all should be addressed directly. Marginal cost pricing without paying uplift to inflexible units would create incentives for market participants to provide flexible

6 Although this recommendation has not been adopted exactly as recommended by the MMU, the implementation of hourly offers by PJM has effectively adopted this recommendation.

7 On September 7, 2018 PJM made a compliance filing for FERC Order No. 844 to publish unit specific uplift credits. The compliance filing has not been accepted by FERC. Absent acceptance from the FERC, PJM will not begin publishing data on unit specific uplift credits.

solutions including replacing inefficient units with flexible, efficient units.

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

Accurate short run price signals, equal to the short run marginal cost of generating power, provide market incentives for cost minimizing production to all economically dispatched resources and provide market incentives to load based on the marginal cost of additional consumption. The objective of efficient short run price signals is to minimize system production costs, not to minimize uplift. Repricing the market to reflect commitment costs would create a tradeoff between minimizing production costs and reduction of uplift. The tradeoff would exist because when commitment costs are included in prices, the price signal no longer equals the short run marginal cost and therefore no longer provides the correct signal for efficient behavior for market participants making decisions on the margin, whether resources, load, interchange transactions, or virtual traders. This tradeoff would be created in more limited form by PJM's fast start pricing proposal (limited convex hull pricing) and in extensive form by PJM's full convex hull pricing proposal.

When units receive substantial revenues through energy uplift payments, these payments are not transparent to the market because of the current confidentiality rules. As a result, other market participants, including generation and transmission developers, do not have the opportunity to compete to displace them. As a result, substantial energy uplift payments to a concentrated group of units and organizations have persisted for more than ten years. FERC Order No. 844 authorized the publication of unit specific uplift payments for credits incurred after January 1, 2019.[8]

One part of addressing the level and allocation of uplift payments is to eliminate all day-ahead operating reserve credits. It is illogical and unnecessary to pay units day-ahead operating reserve credits because units do not incur any costs to run and any revenue shortfalls are addressed by balancing operating reserve credits.

Up to congestion transactions continue to pay no energy uplift charges, which means that all others who pay these charges are paying too much.[9]

PJM needs to pay substantially more attention to the details of uplift payments including accurately tracking whether units are following dispatch, identifying the actual need for units to be dispatched out of merit and determining whether local reserve zones or better definitions of constraints would be a more market based approach.

While energy uplift charges are an appropriate part of the cost of energy, market efficiency would be improved by ensuring that the level and variability of these charges are as low as possible consistent with the reliable operation of the system and consistent with pricing at short run marginal cost. The goal should be to minimize the total incurred energy uplift charges and to increase the transactions over which those charges are spread in order to reduce the impact of energy uplift charges on markets. The result would be to reduce the level of per MWh charges, to reduce the uncertainty associated with uplift charges and to reduce the impact of energy uplift charges on decisions about how and when to participate in PJM markets.

Energy Uplift Results

The level of energy uplift credits paid to specific units depends on the level of the resource's energy offer, the LMP, the resource's operating parameters and the decisions of PJM operators. Energy uplift credits result in part from decisions by PJM operators, who follow

8 Publication of unit specific uplift credits will begin after FERC accepts PJM's Order No. 844 compliance filing.

9 On October 17, 2017, PJM filed with FERC a proposed tariff change to allocate uplift to UTC transactions in the same manner in which uplift is currently allocated to other virtual transactions, as a separate injection and withdrawal deviation. FERC rejected the proposed tariff change. The rejection was without prejudice and PJM has the option to submit a new proposal. See FERC Docket No. ER18-86-000. PJM has not filed a new proposal.

reliability requirements and market rules, to start resources or to keep resources operating even when LMP is less than the offer price including incremental, no load and startup costs. Energy uplift payments also result from units' operational parameters that require PJM to schedule or commit resources when they are not economic. The resulting costs not covered by energy revenues are collected as energy uplift.

In 2018, energy uplift credits increased by $71.8 million compared to 2017, from $127.2 million to $199.0 million. Figure 4-1 shows the net impact of each credit category on the change in total energy uplift credits. The outside bars show the total energy uplift credits paid in 2017 (left side) and 2018 (right side). The interior bars show the change by credit type. The increase was a result of a $9.2 million increase in day-ahead credits, a $25.0 million increase in balancing credits, a $7.0 million increase in local constraint control credits, and a $37.7 million increase in lost opportunity cost credits.

Figure 4-1 Energy uplift credits change from 2017 to 2018 by category

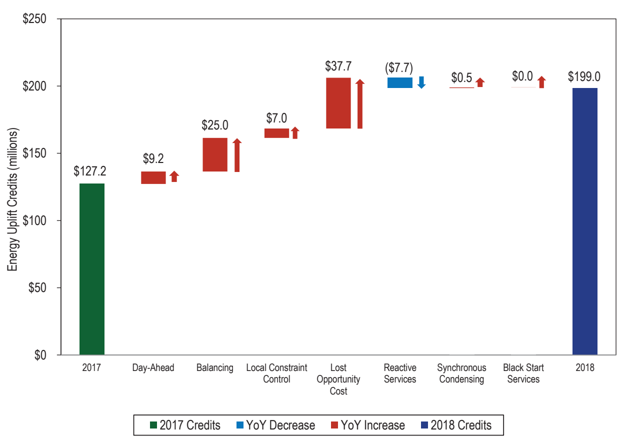


Figure 4-2 shows total uplift credits by month for 2017 and 2018. January 2018 was the highest uplift month in 2018 with $61.6 million or 31.0 percent of all credits in 2018. Out of the $61.6 million, 89.0 percent were balancing operating reserve and lost opportunity cost (LOC) credits ($33.1 million and $21.7 million).

The months of March through June also experienced an increase in uplift credits compared to 2017. This was the results of reliability and local constraint control issues that could only be addressed by specific large inflexible units. The increase in credits was also a result of an increase in LOC credits to CTs. This was result of modeling differences between the day-ahead and real-time markets causing combustion turbines committed in the day-ahead to not be requested in real time despite the units being economic.

Figure 4-2 Total uplift credits by month: 2017 and 2018

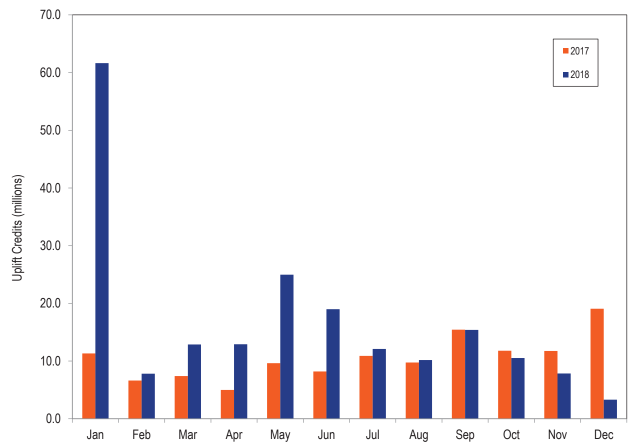


Figure 4-3 shows daily day-ahead, balancing, and lost opportunity cost credits by day for 2018. These three credit types make up 88.9 percent of all uplift credits. Figure 4-4 shows that uplift credits are highly concentrated in a few days. Out of the top ten uplift days in 2018, nine were in January. In those nine days there were $47.7 million in uplift credits. The high uplift on those days was the result of a combination of factors including the extreme cold weather, high natural gas prices, the commitment of large inflexible CTs, the failure of market power mitigation tools that allowed units needed for reliability to clear on price offers with significant mark ups, and differences between the day-ahead and real-time market models which caused commitment and dispatch differences between the day-ahead and real-time markets.[10]

10 See *2018 State of the Market Report for PJM*, Section 3: "Offer Capping for Local Market Power" at "Market Concentration" for a discussion of how generators with market power can evade mitigation.

Figure 4-3 Day-ahead, balancing, and lost opportunity cost uplift credits by day: 2018

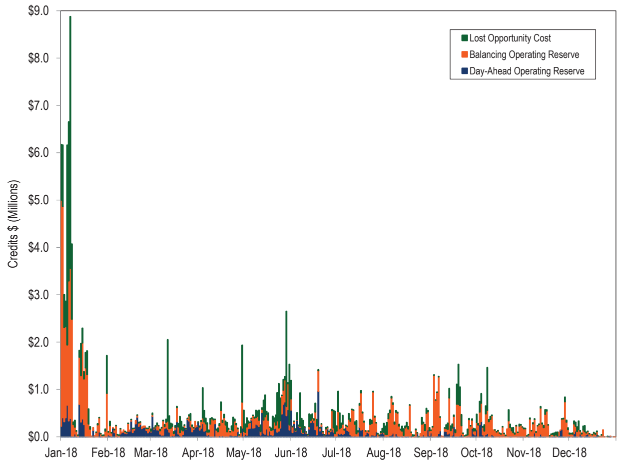


Table 4-1 shows the totals for each credit category in 2017 and 2018.[11] In 2018 energy uplift credits increased by $71.8 million or 56.4 percent compared to 2017.

Table 4-1 Energy uplift credits by category: 2017 and 2018

Category	Type	2017 Credits (Millions)	2018 Credits (Millions)	Change	Percent Change	2017 Share	2018 Share
Day-Ahead	Generators	$24.8	$34.0	$9.2	37.2%	19.5%	17.1%
	Imports	$0.0	$0.0	$0.0	194,450.3%	0.0%	0.0%
	Load Response	$0.0	$0.00	($0.0)	(65.5%)	0.0%	0.0%
Balancing	Canceled Resources	$0.0	$0.0	($0.0)	(100.0%)	0.0%	0.0%
	Generators	$65.3	$90.2	$24.9	38.1%	51.4%	45.3%
	Imports	$0.0	$0.5	$0.5	7,585.7%	0.0%	0.2%
	Load Response	$0.3	$0.0	($0.3)	(98.3%)	0.3%	0.0%
	Local Constraints Control	$1.5	$8.6	$7.0	463.6%	1.2%	4.3%
	Lost Opportunity Cost	$14.6	$52.3	$37.7	258.6%	11.5%	26.3%
Reactive Services	Day-Ahead	$19.3	$11.8	($7.5)	(38.8%)	15.1%	5.9%
	Local Constraints Control	$0.0	$0.0	$0.0	NA	0.0%	0.0%
	Lost Opportunity Cost	$0.2	$0.0	($0.2)	(94.6%)	0.2%	0.0%
	Reactive Services	$0.9	$0.9	($0.0)	(3.8%)	0.7%	0.4%
	Synchronous Condensing	$0.0	$0.5	$0.4	1,328.7%	0.0%	0.2%
Synchronous Condensing		$0.0	$0.0	$0.0	NA	0.0%	0.0%
Black Start Services	Day-Ahead	$0.0	$0.0	$0.0	NA	0.0%	0.0%
	Balancing	$0.0	$0.3	$0.3	1,159.7%	0.0%	0.1%
	Testing	$0.2	$0.0	($0.2)	(90.1%)	0.2%	0.0%
Total		$127.2	$199.0	$71.8	56.4%	100.0%	100.0%

Characteristics of Credits

Types of Units

Table 4-2 shows the distribution of total energy uplift credits by unit type for 2017 and 2018. The largest recipients of uplift credits were combustion turbines and coal fired steam units, receiving 55.0 percent and 22.9 percent of all uplift credits. In 2018, uplift credits to combined cycle units increased by $10.3 million or 102.2 percent compared to 2017. The majority of the increase occurred in January as a result of the extended cold weather. In 2018, uplift credits to gas and oil fired steam units increased by $13.7 million or 235.4 percent compared to 2017. The increase in uplift credits for these units was the result of reliability issues which required specific units to be committed.

11 Billing data can be modified by PJM Settlements at any time to reflect changes in the evaluation of energy uplift. The billing data reflected in this report were current on January 10, 2019.

Table 4-2 Energy uplift credits by unit type: 2017 and 2018

Unit Type	2017 Credits (Millions)	2018 Credits (Millions)	Change	Percent Change	2017 Share	2018 Share
Combined Cycle	$10.1	$20.3	$10.3	102.2%	7.9%	10.2%
Combustion Turbine	$62.1	$109.3	$47.2	76.0%	48.9%	55.0%
Diesel	$0.9	$1.7	$0.8	83.8%	0.7%	0.9%
Hydro	$0.1	$0.0	($0.1)	(100.0%)	0.1%	0.0%
Nuclear	$0.1	$0.4	$0.3	387.3%	0.1%	0.2%
Solar	$0.0	$0.0	($0.0)	(69.3%)	0.0%	0.0%
Steam - Coal	$45.7	$45.5	($0.1)	(0.3%)	36.0%	22.9%
Steam - Other	$5.8	$19.6	$13.7	235.4%	4.6%	9.9%
Wind	$2.2	$1.7	($0.4)	(20.3%)	1.7%	0.9%
Total	$126.9	$198.5	$71.6	56.4%	100.0%	100.0%

Table 4-3 shows the distribution of energy uplift credits by category and by unit type in 2018. The characteristics of the different unit types explain why the shares of credit types are dominated by a particular unit type. For example, the majority of day-ahead credits, 87.8 percent, go to steam units. This is because steam units tend to be longer lead time units that need to be committed before the operating day. If a steam unit is needed for reliability and it is uneconomic it will be committed in the Day-Ahead Energy Market and receive day-ahead credits. Coal fired steam units received 88.0 percent of all reactive service credits as a result of the specific locations of the voltage issues and the location of the units. Combustion turbines, which, unlike other unit types, can be committed and decommitted in the real time market, received 76.4 percent of balancing credits and 71.9 percent of lost opportunity credits. Combustion turbines committed in the real-time market require balancing credits as result of inflexible operating parameters, volatile real-time LMPs, and intraday segment settlements. Combustion turbines with a day-ahead schedule and not committed in real time will receive lost opportunity credits when they incur a loss as a result of not operating. A unit incurs a loss when the real time LMPs are greater than the day-ahead LMPs at the unit's pnode and the unit's balancing charges are greater than its day-ahead revenues.

Table 4-3 Energy uplift credits by unit type: 2018

Unit Type	Day-Ahead Generator	Balancing Generator	Canceled Resources	Local Constraints Control	Lost Opportunity Cost	Reactive Services	Synchronous Condensing	Black Start Services
Combined Cycle	8.6%	13.2%	0.0%	0.0%	10.4%	0.2%	0.0%	20.4%
Combustion Turbine	3.7%	76.4%	0.0%	0.8%	71.9%	8.5%	100.0%	79.6%
Diesel	0.0%	0.6%	0.0%	2.0%	1.7%	1.0%	0.0%	0.0%
Hydro	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Nuclear	0.0%	0.0%	0.0%	0.0%	0.7%	0.0%	0.0%	0.0%
Solar	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Steam - Coal	61.3%	5.5%	0.0%	25.1%	11.6%	88.0%	0.0%	0.0%
Steam - Other	26.5%	4.3%	0.0%	72.2%	0.4%	2.4%	0.0%	0.0%
Wind	0.0%	0.0%	0.0%	0.0%	3.3%	0.0%	0.0%	0.0%
Total (Millions)	$34.0	$90.2	$0.0	$8.6	$52.3	$13.1	$0.0	$0.3

Day-Ahead Unit Commitment for Reliability

PJM may schedule units as must run in the Day-Ahead Energy Market when needed in real time to address reliability issues of various types that would otherwise not have been committed in the day-ahead. Such reliability issues include black start service and reactive service or reactive transfer interface control needed to maintain system reliability in a zone.[12] Participants can submit units as self-scheduled (must run), meaning that the unit must be committed, but a unit submitted as must run by a participant is not eligible for day-ahead operating reserve credits.[13] Units committed for reliability by PJM are eligible for day-ahead operating reserve credits and may set LMP if raised above economic minimum and follow the dispatch signal. Table 4-4 shows the total day-ahead generation and the

12 See PJM Operating Agreement Schedule 1 § 3.2.3(b).

13 See PJM. "PJM Markets Gateway User Guide," Section Managing Unit Data (version July 18, 2017) at 38, <http://www.pjm.com/-/media/etools/markets-gateway/markets-gateway-user-guide.ashx?la=en>.

subset of that generation committed for reliability by PJM. In 2018, 1.3 percent of the total day-ahead generation was committed for reliability by PJM, 0.1 percentage points higher than in 2017.

Table 4-4 Day-ahead generation committed for reliability (GWh): 2017 and 2018

	2017			2018		
	Total Day-Ahead Generation	Day-Ahead PJM Must Run Generation	Share	Total Day-Ahead Generation	Day-Ahead PJM Must Run Generation	Share
Jan	71,967	1,051	1.5%	78,368	1,209	1.5%
Feb	61,356	725	1.2%	63,095	780	1.2%
Mar	66,657	523	0.8%	67,699	1,712	2.5%
Apr	58,457	334	0.6%	59,019	967	1.6%
May	61,170	952	1.6%	65,017	1,799	2.8%
Jun	69,964	634	0.9%	71,001	1,188	1.7%
Jul	79,334	1,157	1.5%	79,653	846	1.1%
Aug	74,129	876	1.2%	80,864	476	0.6%
Sep	65,211	1,047	1.6%	69,596	659	0.9%
Oct	61,308	1,013	1.7%	64,003	533	0.8%
Nov	61,980	589	1.0%	64,183	744	1.2%
Dec	73,448	1,025	1.4%	70,864	215	0.3%
Total	804,982	9,926	1.2%	833,362	11,128	1.3%

Pool-scheduled units and units committed for reliability are made whole in the Day-Ahead Energy Market if their total offer (including no load and startup costs) is greater than the revenues from the Day-Ahead Energy Market. Such units are paid day-ahead operating reserve credits. Total day-ahead operating reserve credits in 2018 were $34.0 million. The top 10 units received $24.2 million or 71.2 percent of all day-ahead operating reserve credits. These units were large units with long commitment times and inflexible operating parameters.

It is illogical and unnecessary to pay units day-ahead operating reserves because units do not incur any costs to run and any revenue shortfalls are addressed by balancing operating reserve payments.

Table 4-5 shows the total day-ahead generation committed for reliability by PJM by category. In 2018, 47.3 percent of the day-ahead generation committed for reliability by PJM received operating reserve credits, 26.7 percent paid as day-ahead operating reserve credits and 20.6 percent paid as reactive services. The remaining 52.7 percent of the day-ahead generation committed for reliability by PJM was economic and did not need to be made whole.

Table 4-5 Day-ahead generation committed for reliability by category (GWh): 2018

	Reactive Services (GWh)	Day-Ahead Operating Reserves (GWh)	Economic (GWh)	Total (GWh)
Jan	154	73	983	1,209
Feb	287	275	218	780
Mar	253	532	928	1,712
Apr	170	163	634	967
May	273	632	893	1,799
Jun	256	532	400	1,188
Jul	79	224	543	846
Aug	95	82	300	476
Sep	142	103	414	659
Oct	344	287	383	1,013
Nov	220	165	204	589
Dec	259	205	561	1,025
Total	2,531	3,272	6,461	12,264
Share	20.6%	26.7%	52.7%	100.0%

Total day-ahead operating reserve credits in 2018 were $34.0 million, of which $23.2 million or 68.1 percent was paid to units committed for reliability by PJM, and not scheduled to provide black start or reactive services. The remaining $10.8 million or 31.9 percent was paid to units scheduled to provide black start or reactive services or were pool-scheduled in the Day-Ahead Energy Market

Balancing Operating Reserve Credits

Balancing operating reserve (BOR) credits are paid to resources operating at PJM's request that do not recover their operating costs from market revenues. BOR credits are calculated as the difference between a resource's revenues (day-ahead market, balancing market, ancillary markets, and day-ahead operating reserve credits) and its real-time costs (startup, no load, and energy offer). Combustion turbines (CTs) received $68.9 million or 76.4 percent of all balancing operating reserve (BOR) credits in 2018. The majority of these credits, 99.3 percent, are paid to CTs that are committed in real time either without or outside of a day-ahead schedule.[14] Such CTs generally are only economic for a short period compared to their minimum run time; operate on more expensive real-time offers compared to day-ahead offers; and are block loaded and provide more energy than is otherwise needed by the system. Uplift is higher than necessary because settlement rules do not include all revenues and costs for the entire day.

Table 4-6 Characteristics of day-ahead and real-time generation by combustion turbines: 2018

Month	Day-Ahead Generation (GWh)	Percent of Day-Ahead Generation that was Noneconomic	Day-Ahead Generator Credits (Millions)	Real-Time Generation (GWh)	Percent of Real-Time Generation that was Noneconomic	Balancing Generator Credits (Millions)	Generation Difference as a Percent of Real-Time Generation
Jan	1,388	4.9%	$1.0	1,257	33.4%	$22.8	(10.4%)
Feb	81	1.2%	$0.0	76	36.9%	$0.8	(6.6%)
Mar	718	1.9%	$0.0	503	22.9%	$1.6	(42.8%)
Apr	1,077	1.9%	$0.0	1,221	33.6%	$5.1	11.7%
May	1,748	1.1%	$0.0	1,670	27.2%	$4.4	(4.7%)
Jun	1,112	1.5%	$0.0	924	22.1%	$1.7	(20.4%)
Jul	1,960	1.9%	$0.0	2,206	23.5%	$6.3	11.2%
Aug	1,572	1.7%	$0.0	1,944	23.5%	$5.9	19.1%
Sep	1,564	1.3%	$0.0	2,078	25.2%	$8.1	24.7%
Oct	1,069	2.8%	$0.0	1,194	29.1%	$5.2	0.0%
Nov	328	2.4%	$0.0	659	39.5%	$5.9	0.0%
Dec	72	6.0%	$0.1	84	36.8%	$1.1	0.0%
Total	12,690	2.1%	$1.3	13,816	27.3%	$68.9	8.2%

The credits paid to CTs committed in real time without a day-ahead commitment occurs despite the fact that combustion turbines are committed in the Day-Ahead Energy Market at levels comparable to the Real-Time Energy Market. Table 4-6 shows the monthly day-ahead and real-time generation by combustion turbines. In 2018, generation by combustion turbines was 8.9 percent greater in the Real-Time Energy Market compared to the Day-Ahead Energy Market. However, this varied month to month, with some months having greater day-ahead generation compared to real-time generation. Table 4-6 shows that only 2.1 percent of generation from combustion turbines in the day-ahead market was uneconomic and only required $1.3 million in day-ahead generator credits. In the Real-Time Energy Market, 27.3 percent of generation from combustion turbines was uneconomic and required $68.9 million in BOR credits.

An analysis of real-time generation by combustion turbines shows that BOR credits are incurred almost exclusively by combustion turbines that operate without or outside a day-ahead schedule. Table 4-7 shows that in 2018, 61.2 percent of real-time generation by CTs was from CTs that operated on a day-ahead schedule. Of the generation from CTs operating on a day-ahead schedule, 17.6 percent was uneconomic in the real-time market and received $0.5 million in BOR credits. Of the 38.8 percent of real-time generation by CTs that operated outside of a day-ahead schedule, 42.5 percent was uneconomic in the real-time market and received $68.4 million in BOR credits. Thus while enough total generation from CTs is committed economically in the Day-Ahead Energy Market, uplift is incurred because the committed units operate at different times than originally scheduled and when CTs that were not committed day ahead operate in real time. For example, in January 2018, although total CT generation committed in the day-ahead market was greater than CT generation in real time, only 48.8 percent of real-time generation by CTs operated on a day-ahead schedule.

14 Operating outside of a day-ahead schedule refers to units that operate for a period either before or after their day-ahead schedule, or are committed in the real-time market and do not have a day-ahead schedule for any part of the day.

There are multiple reasons why the commitment of CTs is different in the day-ahead and real-time markets, including: differences in the hourly pattern of load; differences in interchange transactions; and behavior by other generators. Modeling differences between the day-ahead and real-time markets also affect CT commitment, including: the modeling of different transmission constraints in the day-ahead and real-time market models; the exclusion of soak time for generators in the day-ahead market model; and the different time scales used in the day-ahead and real-time markets.

Table 4-7 Real-time generation by combustion turbines by day-ahead commitment: 2018

	Real-Time Generation Operating on a Day-Ahead Schedule				Real-Time Generation Operating Outside of a Day-Ahead Schedule			
Month	Generation (GWh)	Share of Real-Time Generation	Percent of Generation that was Noneconomic	Balancing Generator Credits (Millions)	Generation (GWh)	Share of Real-Time Generation	Percent of Generation that was Noneconomic	Balancing Generator Credits (Millions)
Jan	613	48.8%	14.4%	$0.4	644	51.2%	51.4%	$22.4
Feb	21	27.9%	12.8%	$0.0	55	72.1%	46.3%	$0.8
Mar	339	67.5%	17.7%	$0.1	164	32.5%	33.5%	$1.5
Apr	698	57.2%	21.7%	$0.0	523	42.8%	49.5%	$5.0
May	1,145	68.6%	18.9%	$0.0	524	31.4%	45.3%	$4.4
Jun	650	70.4%	17.3%	$0.0	274	29.6%	33.4%	$1.7
Jul	1,484	67.2%	18.0%	$0.0	723	32.8%	34.8%	$6.3
Aug	1,241	63.9%	17.5%	$0.0	702	36.1%	34.0%	$5.9
Sep	1,218	58.6%	14.7%	$0.0	860	41.4%	40.0%	$8.1
Oct	781	65.4%	17.4%	$0.0	413	34.6%	51.4%	$5.2
Nov	240	36.5%	22.8%	$0.0	418	63.5%	49.1%	$5.9
Dec	24	28.4%	26.4%	$0.0	60	71.6%	40.9%	$1.1
Total	8,455	61.2%	17.6%	$0.5	5,360	38.8%	42.5%	$68.4

Lost Opportunity Cost Credits

Balancing operating reserve lost opportunity cost (LOC) credits are an incentive for units to follow PJM's dispatch instructions when PJM's dispatch instructions deviate from a unit's desired or scheduled output. LOC credits are paid under two different scenarios. The first scenario occurs if a unit of any type generating in real time with an offer price lower than the real-time LMP at the unit's bus is reduced or suspended by PJM due to a transmission constraint or other reliability issue. In this scenario the unit will receive a credit for LOC based on its desired output. This LOC will be referred to as real-time LOC. The second scenario occurs if a combustion turbine or diesel engine is scheduled to operate in the Day-Ahead Energy Market, but it is not requested by PJM in real time. In this scenario the unit will receive a credit which covers any loss in the day-ahead financial position of the unit plus the balancing spot energy market position. This LOC will be referred to as day-ahead LOC.

Table 4-8 shows monthly day-ahead and real-time LOC credits in 2017 and 2018. In 2018, LOC credits increased by $37.7 million or 258.6 percent compared to 2017. The increase of $37.7 million is comprised of a $27.6 million increase in day-ahead LOC and a $10.1 million increase in real-time LOC. Table 4-9 shows for combustion turbines and diesels scheduled day-ahead generation, scheduled day-ahead generation not requested in real time, and the subset of day-ahead generation receiving LOC credits. In 2018, 15.0 percent of day-ahead generation by combustion turbines and diesels was not requested in real time, 4.0 percentage points higher than in 2017.

Table 4-8 Monthly lost opportunity cost credits (Millions): 2017 and 2018

	2017			2018		
	Day-Ahead Lost Opportunity Cost	Real-Time Lost Opportunity Cost	Total	Day-Ahead Lost Opportunity Cost	Real-Time Lost Opportunity Cost	Total
Jan	$0.1	$0.3	$0.4	$13.7	$8.0	$21.7
Feb	$0.1	$0.1	$0.1	$0.1	$0.0	$0.2
Mar	$0.9	$0.2	$1.1	$3.2	$0.2	$3.4
Apr	$0.5	$0.3	$0.8	$2.0	$1.9	$3.9
May	$0.8	$1.0	$1.8	$6.0	$2.8	$8.8
Jun	$0.7	$0.8	$1.5	$3.5	$0.0	$3.5
Jul	$1.5	$0.2	$1.7	$2.1	$0.0	$2.1
Aug	$0.5	$0.1	$0.6	$1.7	$0.1	$1.9
Sep	$1.5	$0.5	$1.9	$2.2	$0.7	$2.9
Oct	$0.8	$0.2	$0.9	$1.9	$0.7	$2.5
Nov	$0.5	$0.3	$0.8	$0.5	$0.2	$0.7
Dec	$2.3	$0.6	$3.0	$0.7	$0.1	$0.8
Total	$10.1	$4.5	$14.6	$37.7	$14.6	$52.3
Share	69%	31%	100%	72%	28%	100%

Table 4-9 Day-ahead generation from combustion turbines and diesels (GWh): 2017 and 2018

	2017			2018		
	Day-Ahead Generation	Day-Ahead Generation Not Requested in Real Time	Day-Ahead Generation Not Requested in Real Time Receiving LOC Credits	Day-Ahead Generation	Day-Ahead Generation Not Requested in Real Time	Day-Ahead Generation Not Requested in Real Time Receiving LOC Credits
Jan	343	33	9	1,893	382	223
Feb	304	27	9	296	40	19
Mar	762	128	49	1,012	252	109
Apr	458	88	28	1,377	204	71
May	658	75	38	2,093	378	149
Jun	1,137	120	61	1,430	328	105
Jul	1,800	265	123	2,340	279	76
Aug	1,325	121	51	1,970	181	58
Sep	2,189	123	66	1,883	202	97
Oct	1,833	136	63	1,396	156	60
Nov	752	101	35	606	55	25
Dec	893	211	108	316	41	21
Total	12,455	1,428	639	16,612	2,496	1,013
Share	100%	11%	5%	100%	15%	6%

Uplift Eligibility

In PJM, units can have either a pool scheduled or self-scheduled commitment status. Pool scheduled units are committed by PJM as a result of the day-ahead market clearing auction while self-scheduled units are committed by generation owners. Table 4-10 provides a description of commitment and dispatch status, uplift eligibility and the ability to set price.[15] In the Day-Ahead Energy Market only pool-scheduled resources are eligible for day-ahead operating reserve credits. In the Real-Time Energy Market only pool-scheduled resources that follow PJM's dispatch are eligible for balancing operating reserve credits. Units are paid day-ahead operating reserve credits based on their scheduled operation for the entire day. Balancing operating reserve credits are paid on a segmented basis for each period defined by the greater of the day-ahead schedule and minimum run time. Resources receive day-ahead and balancing operating reserve credits only when they are eligible and unable to recover their operating cost for the day or segment.[16]

15 PJM has modified the basic rules of eligibility to set price using its CT price setting logic.

16 Resources do not recover their operating cost when market revenues for the day are less than the short run marginal cost defined by the startup, no load, and incremental offer curve.

Table 4-10 Dispatch status, commitment status and uplift eligibility

Dispatch Status	Dispatch Description	Eligible to Set LMP	Commitment Status: Self Scheduled (units committed by the generation owner)	Commitment Status: Pool Scheduled (units committed by PJM)
Block Loaded	MWh offered to PJM as a single MWh block which is not dispatchable	No	Not eligible to receive uplift	Eligible to receive uplift
Economic Minimum	MWh from the nondispatchable economic minimum component for units that offer a dispatchable range to PJM	No	Not eligible to receive uplift	Eligible to receive uplift
Dispatchable	MWh above the economic minimum level for units that offer a dispatchable range to PJM.	Yes	Only eligible to receive LOC credits if dispatched down by PJM	Eligible to receive uplift

Table 4-11 shows day-ahead and real-time generation by commitment and dispatch status. Table 4-11 shows that in 2018, 39.4 percent of generation was pool-scheduled in the Day-Ahead Energy Market and 41.2 percent was pool-scheduled in the Real-Time Energy Market. Thus the majority of generation in both the day-ahead and real-time markets is not eligible to receive uplift credits. This occurs because the majority of nuclear and coal resources, which make up 63.1 percent of real-time generation, are self-scheduled.

Table 4-11 Day-ahead and real-time generation by status and eligibility to set LMP (GWh): 2018

	Self Scheduled			Pool Scheduled						
	Dispatchable	Ecomin	Block Loaded	Dispatchable	Ecomin	Block Loaded	Total GWh	Total Pool Scheduled	Total Self Scheduled	Total Generation Eligible to Set Price
Day-Ahead Generation	96,161	187,874	220,917	140,405	163,094	24,910	833,362	328,410	504,952	236,567
Share of Day-Ahead	11.5%	22.5%	26.5%	16.8%	19.6%	3.0%	100.0%	39.4%	60.6%	28.4%
Real-Time Generation	81,262	153,766	256,317	131,935	179,522	32,734	835,536	344,191	491,345	213,197
Share of Real-Time	9.7%	18.4%	30.7%	15.8%	21.5%	3.9%	100.0%	41.2%	58.8%	25.5%

Economic and Noneconomic Generation[17]

Economic generation includes units scheduled day ahead or producing energy in real time at an incremental offer less than or equal to the LMP at the unit's bus. Noneconomic generation includes units that are scheduled to or produce energy in real time at an incremental offer higher than the LMP at the unit's bus. The MMU analyzed PJM's day-ahead and real time generation eligible for operating reserve credits to determine the shares of economic and noneconomic generation. Each unit's hourly generation was determined to be economic or noneconomic based on the unit's hourly incremental offer, excluding the hourly no load and any applicable startup cost. A unit could be economic for every hour during a day or segment, but still receive operating reserve credits because the energy revenues did not cover the hourly no load and startup cost. A unit could be noneconomic for multiple hours and not receive operating reserve credits whenever the total revenues covered the total offer (including no load and startup cost) for the entire day or segment.

Table 4-12 shows the day-ahead and real-time economic and noneconomic generation from units eligible for operating reserve credits. In 2018, 84.6 percent of the day-ahead generation eligible for operating reserve credits was economic and 68.6 percent of the real-time generation eligible for operating reserve credits was economic. A unit's generation may be noneconomic for a portion of their daily generation and economic for the rest. Table 4-12 shows the separate amounts of economic and noneconomic generation even if the daily or segment generation was economic.

Table 4-12 Economic and noneconomic generation from units eligible for operating reserve credits (GWh): 2018

Energy Market	Economic Generation	Noneconomic Generation	Total Eligible Generation	Economic Generation Percent	Noneconomic Generation Percent
Day-Ahead	277,837	50,572	328,410	84.6%	15.4%
Real-Time	211,379	96,792	308,170	68.6%	31.4%

17 The analysis of economic and noneconomic generation is based on units' incremental offers, the value used by PJM to calculate LMP. The analysis does not include no load or startup costs.

Noneconomic generation only leads to operating reserve credits when a unit is unable to recover its operating costs for the day or segment. Table 4-13 shows the generation receiving day-ahead and balancing operating reserve credits. In 2018, 2.2 percent of the day-ahead generation eligible for operating reserve credits received credits and 1.8 percent of the real-time generation eligible for operating reserve credits received credits.

Table 4-13 Generation receiving operating reserve credits (GWh): 2018

Energy Market	Generation Eligible for Operating Reserve Credits	Generation Receiving Operating Reserve Credits	Generation Receiving Operating Reserve Credits Percent
Day-Ahead	328,410	7,178	2.2%
Real-Time	308,170	5,682	1.8%

Concentration of Energy Uplift Credits

There is a high level of concentration in the units and companies receiving energy uplift credits. This concentration results from a combination of unit operating parameters, PJM's persistent need to commit specific units out of merit in particular locations and the fact that the lack of transparency makes it almost impossible for competition to affect these payments.[18]

Figure 4-4 shows the concentration of energy uplift credits. The top 10 units received 21.2 percent of total energy uplift credits in 2018, compared to 33.6 percent in 2017. In 2018, 310 units received 90 percent of all energy uplift credits, compared to 267 units in 2017.

Figure 4-4 Cumulative share of energy uplift credits: 2017 and 2018 by unit

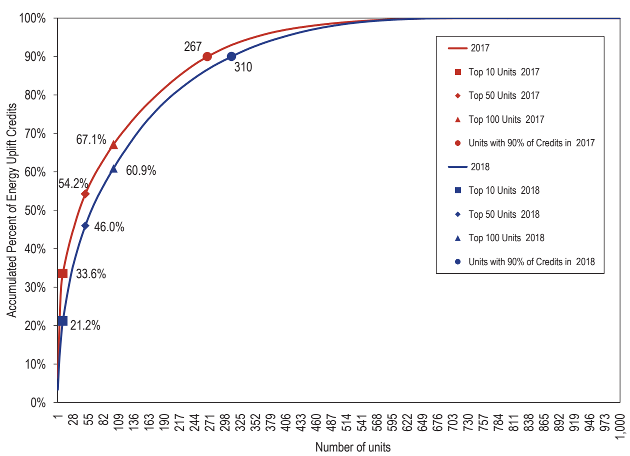


Table 4-14 shows the credits received by the top 10 units and top 10 organizations in each of the energy uplift categories paid to generators in 2018.

Table 4-14 Top 10 units and organizations energy uplift credits: 2018

		Top 10 Units		Top 10 Organizations	
Category	Type	Credits (Millions)	Credits Share	Credits (Millions)	Credits Share
Day-Ahead	Generators	$24.2	71.2%	$33.0	97.0%
Balancing	Canceled Resources	$0.0	0.0%	$0.0	0.0%
	Generators	$11.1	12.3%	$64.6	71.6%
	Local Constraints Control	$8.5	99.5%	$8.6	100.0%
	Lost Opportunity Cost	$9.3	17.7%	$37.5	71.8%
Reactive Services		$12.6	96.0%	$13.1	100.0%
Synchronous Condensing		$0.0	100.0%	$0.0	100.0%
Black Start Services		$0.1	48.0%	$0.3	90.8%
Total		$42.1	21.2%	$148.2	74.6%

18 As a result of FERC Order No. 844 PJM will begin publishing total uplift credits by unit by month for credits incurred after January 1, 2019. Data postings will begin pending FERC's approval of PJM's September 7, 2018 Order No. 844 compliance filing.

Table 4-15 shows balancing operating reserve credits received by the top 10 units identified for reliability or for deviations in each region. In 2018, 65.4 percent of all credits paid to these units were allocated to deviations while the remaining 34.6 percent were paid for reliability reasons.

Table 4-15 Balancing operating reserve credits to top 10 units by category and region: 2018

	Reliability			Deviations			
	RTO	East	West	RTO	East	West	Total
Credits (Millions)	$3.1	$0.1	$0.6	$5.3	$0.3	$1.7	$11.1
Share	27.8%	1.2%	5.6%	47.5%	2.5%	15.4%	100.0%

In 2018, concentration in all energy uplift credit categories was high.[19] [20] The HHI for energy uplift credits was calculated based on each organization's share of daily credits for each category. Table 4-16 shows the average HHI for each category. HHI for day-ahead operating reserve credits to generators was 8013, for balancing operating reserve credits to generators was 2865, for lost opportunity cost credits was 4860 and for reactive services credits was 9713. All of these HHI values are characterized as highly concentrated.

Table 4-16 Daily energy uplift credits HHI: 2018

Category	Type	Average	Minimum	Maximum	Highest Market Share (One day)	Highest Market Share (All days)
Day-Ahead	Generators	8013	2685	10000	100.0%	57.9%
	Imports	10000	10000	10000	100.0%	99.9%
	Load Response	10000	10000	10000	100.0%	81.5%
Balancing	Canceled Resources	NA	NA	NA	NA	NA
	Generators	2865	735	10000	100.0%	17.8%
	Imports	10000	10000	10000	100.0%	100.0%
	Load Response	9997	9944	10000	100.0%	47.4%
	Lost Opportunity Cost	4860	911	10000	100.0%	26.0%
Reactive Services		9713	4203	10000	100.0%	89.3%
Synchronous Condensing		10000	10000	10000	100.0%	100.0%
Black Start Services		9580	3968	10000	100.0%	52.5%
Total		3002	735	10000	100.0%	21.5%

Credits and Charges Categories

Energy uplift charges include day-ahead and balancing operating reserves, reactive services, synchronous condensing and black start services categories. Total energy uplift credits paid to PJM participants equal the total energy uplift charges paid by PJM participants. Table 4-17 and Table 4-18 show the categories of credits and charges and their relationship. These tables show how the charges are allocated.

19 See *2018 State of the Market Report for PJM*, Section 3: "Energy Market" at "Market Concentration" for a discussion of concentration ratios and the Herfindahl-Hirschman Index (HHI).
20 Table 4-16 excludes local constraint control categories.

Table 4-17 Day-ahead and balancing operating reserve credits and charges

Credits Received For:	Credits Category:		Charges Category:	Charges Paid By:	
		Day-Ahead			
Day-Ahead Import Transactions and Generation Resources	Day-Ahead Operating Reserve Transaction Day-Ahead Operating Reserve Generator	→	Day-Ahead Operating Reserve	Day-Ahead Load Day-Ahead Export Transactions Decrement Bids	in RTO Region
Economic Load Response Resources	Day-Ahead Operating Reserves for Load Response	→	Day-Ahead Operating Reserve for Load Response	Day-Ahead Load Day-Ahead Export Transactions Decrement Bids	in RTO Region
Unallocated Negative Load Congestion Charges Unallocated Positive Generation Congestion Credits		→	Unallocated Congestion	Day-Ahead Load Day-Ahead Export Transactions Decrement Bids	in RTO Region
		Balancing			
Generation Resources	Balancing Operating Reserve Generator	→	Balancing Operating Reserve for Reliability	Real-Time Load plus Real-Time Export Transactions	in RTO, Eastern or Western Region
			Balancing Operating Reserve for Deviations	Deviations	
			Balancing Local Constraint	Applicable Requesting Party	
Canceled Resources	Balancing Operating Reserve Startup Cancellation	→	Balancing Operating Reserve for Deviations	Deviations	in RTO Region
Lost Opportunity Cost (LOC)	Balancing Operating Reserve LOC				
Real-Time Import Transactions	Balancing Operating Reserve Transaction				
Economic Load Response Resources	Balancing Operating Reserves for Load Response	→	Balancing Operating Reserve for Load Response	Deviations	in RTO Region

Table 4-18 Reactive services, synchronous condensing and black start services credits and charges

Credits Received For:	Credits Category:		Charges Category:	Charges Paid By:
		Reactive		
Resources Providing Reactive Service	Day-Ahead Operating Reserve Reactive Services Generator Reactive Services LOC Reactive Services Condensing Reactive Services Synchronous Condensing LOC	→	Reactive Services Charge	Zonal Real-Time Load
			Reactive Services Local Constraint	Applicable Requesting Party
		Synchronous Condensing		
Resources Providing Synchronous Condensing	Synchronous Condensing Synchronous Condensing LOC	→	Synchronous Condensing	Real-Time Load Real-Time Export Transactions
		Black Start		
Resources Providing Black Start Service	Day-Ahead Operating Reserve Balancing Operating Reserve Black Start Testing	→	Black Start Service Charge	Zone/Non-zone Peak Transmission Use and Point to Point Transmission Reservations

Energy Uplift Results

Energy Uplift Charges Total energy uplift charges increased by $72.0 million or 56.5 percent in 2018 compared to 2017. Table 4-20 shows total energy uplift charges for 2001 through 2018.

Table 4-19 Total energy uplift charges: 2001 through 2018

	Total Energy Uplift Charges (Millions)	Change (Millions)	Percent Change	Energy Uplift as a Percent of Total PJM Billing
2001	$284.0	$67.0	30.9%	8.5%
2002	$273.7	($10.3)	(3.6%)	5.8%
2003	$376.5	$102.8	37.6%	5.4%
2004	$537.6	$161.1	42.8%	6.1%
2005	$712.6	$175.0	32.6%	3.1%
2006	$365.6	($347.0)	(48.7%)	1.7%
2007	$503.3	$137.7	37.7%	1.6%
2008	$474.3	($29.0)	(5.8%)	1.4%
2009	$322.7	($151.6)	(32.0%)	1.2%
2010	$623.2	$300.5	93.1%	1.8%
2011	$603.4	($19.8)	(3.2%)	1.7%
2012	$649.8	$46.4	7.7%	2.2%
2013	$843.0	$193.2	29.7%	2.5%
2014	$961.2	$118.2	14.0%	1.9%
2015	$312.0	($649.2)	(67.5%)	0.7%
2016	$136.7	($175.3)	(56.2%)	0.4%
2017	$127.3	($9.4)	(6.9%)	0.3%
2018	$199.3	$72.0	56.5%	0.4%

Table 4-20 shows total energy uplift charges by category in 2017 and 2018.[21] The increase of $72.0 million is comprised of an increase of $9.2 million in day-ahead operating reserve charges, an increase of $69.9 million in balancing operating reserve charges and a decrease of $7.3 million in reactive service charges.

Table 4-20 Total energy uplift charges by category: 2017 and 2018

Category	2017 Charges (Millions)	2018 Charges (Millions)	Change (Millions)	Percent Change
Day-Ahead Operating Reserves	$24.8	$34.0	$9.2	37.2%
Balancing Operating Reserves	$81.9	$151.8	$69.9	85.4%
Reactive Services	$20.4	$13.1	($7.3)	(35.6%)
Synchronous Condensing	$0.0	$0.0	$0.0	0.0%
Black Start Services	$0.3	$0.3	$0.0	17.9%
Total	$127.3	$199.3	$72.0	56.5%
Energy Uplift as a Percent of Total PJM Billing	0.3%	0.4%	0.1%	26.3%

Table 4-21 compares monthly energy uplift charges by category for 2017 and 2018.

21 Table 4-20 includes all categories of charges as defined in Table 4-17 and Table 4-18 and includes all PJM Settlements billing adjustments. Billing data can be modified by PJM Settlements at any time to reflect changes in the evaluation of energy uplift. The billing data reflected in this report were current on January 10, 2019.

Table 4-21 Monthly energy uplift charges: 2017 and 2018

	2017 Charges (Millions)						2018 Charges (Millions)					
	Day-Ahead	Balancing	Reactive Services	Synchronous Condensing	Black Start Services	Total	Day-Ahead	Balancing	Reactive Services	Synchronous Condensing	Black Start Services	Total
Jan	$2.6	$7.5	$1.3	$0.0	$0.0	$11.4	$4.8	$55.4	$1.94	$0.0	$0.0	$62.1
Feb	$2.0	$1.3	$3.3	$0.0	$0.0	$6.6	$3.6	$1.9	$2.2	$0.0	$0.0	$7.8
Mar	$0.6	$5.4	$1.4	$0.0	$0.0	$7.4	$4.6	$6.4	$1.9	$0.0	$0.0	$12.9
Apr	$0.5	$3.2	$1.3	$0.0	$0.0	$5.0	$2.1	$9.6	$1.2	$0.0	$0.1	$12.9
May	$0.9	$7.4	$1.3	$0.0	$0.0	$9.7	$6.9	$16.1	$2.2	$0.0	$0.1	$25.2
Jun	$1.8	$5.5	$0.9	$0.0	$0.0	$8.3	$5.7	$12.0	$1.3	$0.0	$0.0	$19.0
Jul	$2.5	$7.5	$0.9	$0.0	$0.0	$10.9	$2.1	$9.5	$0.5	$0.0	$0.0	$12.1
Aug	$2.9	$5.4	$1.5	$0.0	$0.0	$9.8	$0.7	$9.2	$0.2	$0.0	$0.0	$10.2
Sep	$3.0	$10.3	$2.3	$0.0	$0.0	$15.5	$1.35	$13.0	$1.0	$0.0	$0.0	$15.4
Oct	$1.6	$7.9	$2.2	$0.0	$0.0	$11.8	$1.0	$8.9	$0.5	$0.0	$0.1	$10.5
Nov	$2.1	$7.7	$1.9	$0.0	$0.0	$11.8	$0.6	$7.0	$0.2	$0.0	$0.0	$7.8
Dec	$4.0	$12.8	$2.3	$0.0	$0.0	$19.1	$0.5	$2.7	$0.0	$0.0	$0.0	$3.3
Total	$24.8	$81.9	$20.4	$0.0	$0.3	$127.3	$34.0	$151.8	$13.1	$0.0	$0.3	$199.3
Share	19.5%	64.3%	16.0%	0.0%	0.2%	100.0%	17.1%	76.2%	6.6%	0.0%	0.2%	100.0%

Table 4-22 shows the composition of day-ahead operating reserve charges. Day-ahead operating reserve charges consist of day-ahead operating reserve charges that pay for credits to generators and import transactions, day-ahead operating reserve charges for economic load response resources and day-ahead operating reserve charges from unallocated congestion charges.[22] Day-ahead operating reserve charges increased by $9.2 million or 37.2 percent in 2018 compared to 2017. Day-ahead operating reserve charges increased in 2018 due to reliability issues in the BGE and Pepco control zones as a result of new flow patterns, voltage issues in the ComEd and DPL zones, and the high load in early January which required additional commitments in the Day-Ahead Energy Market.

Table 4-22 Day-ahead operating reserve charges: 2017 and 2018

Type	2017 Charges (Millions)	2018 Charges (Millions)	Change (Millions)	2017 Share	2018 Share
Day-Ahead Operating Reserve Charges	$24.8	$34.0	$9.2	100.0%	100.0%
Day-Ahead Operating Reserve Charges for Load Response	$0.0	$0.0	($0.0)	0.0%	0.0%
Unallocated Congestion Charges	$0.0	$0.0	$0.0	0.0%	0.0%
Total	$24.8	$34.0	$9.2	100.0%	100.0%

Table 4-23 shows the composition of the balancing operating reserve charges. Balancing operating reserve charges consist of balancing operating reserve reliability charges (credits to generators), balancing operating reserve deviation charges (credits to generators and import transactions), balancing operating reserve charges for economic load response and balancing local constraint charges. Balancing operating reserve charges increased by $69.9 million in 2018 compared to 2017.

Table 4-23 Balancing operating reserve charges: 2017 and 2018

Type	2017 Charges (Millions)	2018 Charges (Millions)	Change (Millions)	2017 Share	2018 Share
Balancing Operating Reserve Reliability Charges	$26.7	$37.1	$10.3	32.7%	24.4%
Balancing Operating Reserve Deviation Charges	$53.3	$106.2	$52.9	65.1%	69.9%
Balancing Operating Reserve Charges for Load Response	$0.4	$0.0	($0.3)	0.4%	0.0%
Balancing Local Constraint Charges	$1.5	$8.6	$7.0	1.9%	5.6%
Total	$81.9	$151.8	$69.9	100.0%	100.0%

Table 4-24 shows the composition of the balancing operating reserve deviation charges. Balancing operating reserve deviation charges equal make whole credits paid to generators and import transactions; energy lost opportunity costs paid to generators; and payments to resources scheduled by PJM but canceled by PJM before coming online. In 2018, energy lost opportunity cost deviation charges increased by $37.9 million or 258.3 percent, and make whole

22 See PJM Operating Agreement Schedule 1 § 3.2.3(c). Unallocated congestion charges are added to the total costs of day-ahead operating reserves. Congestion charges have been allocated to day-ahead operating reserves only 10 times, totaling $26.9 million.

deviation charges increased by $15.0 million or 38.9 percent compared to 2017. The increase in charges was the result of an increase in balancing and lost opportunity cost credits to generators.

Table 4-24 Balancing operating reserve deviation charges: 2017 and 2018

Charge Attributable To	2017 Charges (Millions)	2018 Charges (Millions)	Change (Millions)	2017 Share	2018 Share
Make Whole Payments to Generators and Imports	$38.6	$53.6	$15.0	72.4%	50.5%
Energy Lost Opportunity Cost	$14.7	$52.6	$37.9	27.5%	49.5%
Canceled Resources	$0.0	$0.0	($0.0)	0.0%	0.0%
Total	$53.3	$106.2	$52.9	100.0%	100.0%

Table 4-25 shows reactive services, synchronous condensing and black start services charges. Reactive services charges decreased by $7.2 million in 2018, compared to 2017. Reactive charges were incurred as a result of high voltage issues in the ComEd and DPL control zones, and low voltage issues in the PENELEC and AEP control zones. The decrease in reactive service charges resulted from a decrease in the need for reactive service in the BGE and Pepco zones.

Table 4-25 Additional energy uplift charges: 2017 and 2018

Type	2017 Charges (Millions)	2018 Charges (Millions)	Change (Millions)	2017 Share	2018 Share
Reactive Services Charges	$20.4	$13.1	($7.3)	98.8%	97.4%
Synchronous Condensing Charges	$0.0	$0.0	$0.0	0.0%	0.3%
Black Start Services Charges	$0.3	$0.3	$0.0	1.2%	2.3%
Total	$20.6	$13.5	($7.2)	100.0%	100.0%

Table 4-26 and Table 4-27 show the amount and shares of regional balancing charges in 2017 and 2018. Regional balancing operating reserve charges consist of balancing operating reserve reliability and deviation charges. These charges are allocated regionally across PJM. In 2018 the largest share of regional charges was paid by demand deviations which paid 42.8 percent of all regional balancing charges. The regional balancing charges allocation table does not include charges attributed for resources controlling local constraints.

In 2018, regional balancing operating reserve charges increased by $63.2 million compared to 2017. Balancing operating reserve reliability charges increased by $10.36 million, or 38.6 percent, and balancing operating reserve deviation charges increased by $52.8 million, or 99.1 percent.

Table 4-26 Regional balancing charges allocation (Millions): 2017

Charge	Allocation	RTO		East		West		Total	
Reliability Charges	Real-Time Load	$21.5	26.8%	$4.0	4.9%	$0.4	0.5%	$25.8	32.2%
	Real-Time Exports	$0.7	0.9%	$0.2	0.2%	$0.0	0.0%	$0.9	1.2%
	Total	$22.2	27.7%	$4.1	5.1%	$0.4	0.5%	$26.7	33.4%
Deviation Charges	Demand	$30.0	37.4%	$2.2	2.7%	$0.5	0.7%	$32.7	40.8%
	Supply	$9.1	11.4%	$0.7	0.8%	$0.1	0.1%	$9.9	12.3%
	Generator	$9.9	12.4%	$0.7	0.9%	$0.1	0.2%	$10.8	13.5%
	Total	$49.0	61.2%	$3.5	4.4%	$0.8	1.0%	$53.3	66.6%
Total Regional Balancing Charges		$71.2	88.9%	$7.6	9.5%	$1.2	1.5%	$80.1	100%

Table 4-27 Regional balancing charges allocation (Millions): 2018

Charge	Allocation	RTO		East		West		Total	
Reliability Charges	Real-Time Load	$31.4	21.9%	$2.9	2.0%	$1.6	1.1%	$35.9	25.1%
	Real-Time Exports	$1.0	0.7%	$0.1	0.1%	$0.0	0.0%	$1.2	0.8%
	Total	$32.4	22.6%	$3.0	2.1%	$1.6	1.1%	$37.1	25.9%
Deviation Charges	Demand	$56.9	39.7%	$1.9	1.3%	$2.4	1.7%	$61.3	42.8%
	Supply	$17.5	12.2%	$0.8	0.6%	$0.7	0.5%	$19.0	13.3%
	Generator	$24.0	16.8%	$0.9	0.6%	$1.1	0.7%	$25.9	18.1%
	Total	$98.5	68.7%	$3.6	2.5%	$4.1	2.9%	$106.2	74.1%
Total Regional Balancing Charges		$130.9	91.4%	$6.6	4.6%	$5.8	4.0%	$143.3	100%

Operating Reserve Rates

Under the operating reserves cost allocation rules, PJM calculates nine separate rates, a day-ahead operating reserve rate, a reliability rate for each region, a deviation rate for each region, a lost opportunity cost rate and a canceled resources rate for the entire RTO region. Table 4-17 shows how these charges are allocated.[23]

Figure 4-5 shows the daily day-ahead operating reserve rate for 2017 and 2018. The average rate in was $0.041 per MWh, $0.011 per MWh higher than the average in 2017. The highest rate of 2018 occurred on June 19, when the rate reached $0.357 per MWh, $0.011 per MWh higher than the $0.346 per MWh reached in 2017, on November 30. Figure 4-5 also shows the daily day-ahead operating reserve rate including the congestion charges allocated to day-ahead operating reserves. There were no congestion charges allocated to day-ahead operating reserves in 2017 or 2018.

Figure 4-5 Daily day-ahead operating reserve rate ($/MWh): 2017 and 2018

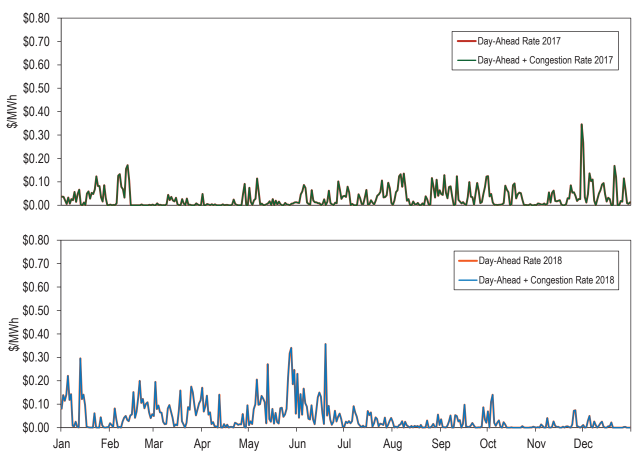


Figure 4-6 shows the RTO and the regional reliability rates for 2017 and 2018. The average RTO reliability rate 2018 was $0.040 per MWh. The highest RTO reliability rate in 2018 occurred on January 2, when the rate reached $0.731 per MWh, $0.341 per MWh higher than the $0.390 per MWh rate reached in 2017, on January 8.

Figure 4-6 Daily balancing operating reserve reliability rates ($/MWh): 2017 and 2018

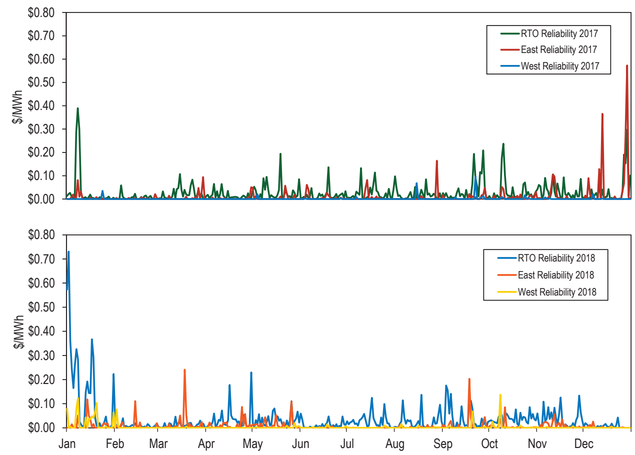


Figure 4-7 shows the RTO and regional deviation rates for 2017 and 2018. The average RTO deviation rate of 2018 was $0.297 per MWh. The highest daily rate of 2018 occurred on January 1, when the RTO deviation rate reached $4.48 per MWh, $2.311 per MWh higher than the $2.177 per MWh rate reached in 2017, on January 9.

Figure 4-7 Daily balancing operating reserve deviation rates ($/MWh): 2017 and 2018

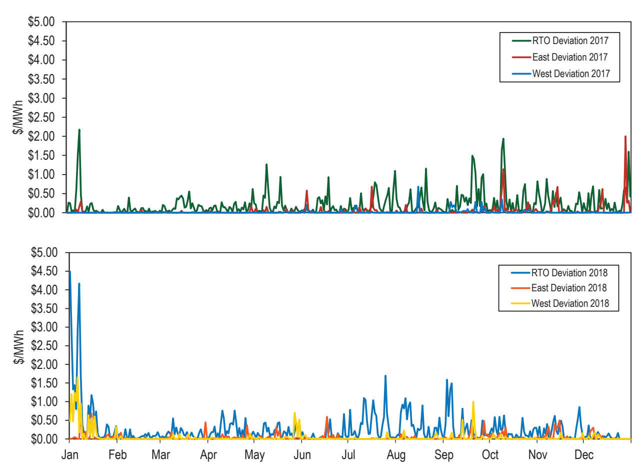


Figure 4-8 shows the daily lost opportunity cost rate and the daily canceled resources rate for 2017 and 2018. The average lost opportunity cost rate of 2018 was $0.341 per MWh. The highest lost opportunity cost rate occurred on January 7, when it reached $9.016 per

23 The lost opportunity cost and canceled resources rates are not posted separately by PJM. PJM adds the lost opportunity cost and the canceled resources rates to the deviation rate for the RTO Region since these three charges are allocated following the same rules.

MWh, $7.059 per MWh higher than the $1.957 per MWh rate reached in 2017, on December 27.[24]

Figure 4-8 Daily lost opportunity cost and canceled resources rates ($/MWh): 2017 and 2018

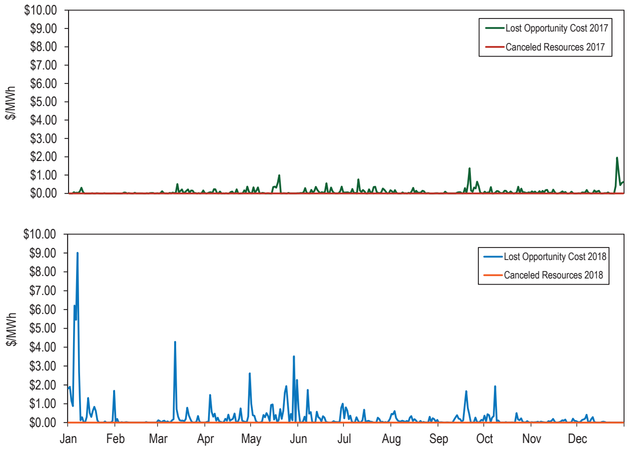


Table 4-28 shows the average rates for each region in each category for 2017 and 2018.

Table 4-28 Operating reserve rates ($/MWh): 2017 and 2018

Rate	2017 ($/MWh)	2018 ($/MWh)	Difference ($/MWh)	Percent Difference
Day-Ahead	0.030	0.041	0.011	35.0%
Day-Ahead with Unallocated Congestion	0.030	0.041	0.011	35.0%
RTO Reliability	0.028	0.040	0.012	40.9%
East Reliability	0.011	0.008	(0.003)	(31.3%)
West Reliability	0.001	0.004	0.003	272.8%
RTO Deviation	0.226	0.297	0.071	31.4%
East Deviation	0.045	0.044	(0.000)	(0.8%)
West Deviation	0.011	0.057	0.046	419.9%
Lost Opportunity Cost	0.097	0.340	0.243	251.6%
Canceled Resources	0.000	-	(0.000)	

Table 4-29 shows the operating reserve cost of a one MW transaction in 2018. For example, a decrement bid in the Eastern Region (if not offset by other transactions) paid an average rate of $0.681 per MWh with a maximum rate of $13.336 per MWh, a minimum rate of $0.000 per MWh and a standard deviation of $1.126 per MWh. The rates in Table 4-29 include all operating reserve charges including RTO deviation charges. Table 4-29 illustrates both the average level of operating reserve charges by transaction types and the uncertainty reflected in the maximum, minimum and standard deviation levels. INCs and DECs have higher rates compared to real-time load because they are allocated a deviation charge while day-ahead and real-time load do not necessarily incur a deviation charge.

Table 4-29 Operating reserve rates statistics ($/MWh): 2018

		Rates Charged ($/MWh)			
Region	Transaction	Maximum	Average	Minimum	Standard Deviation
East	INC	13.194	0.681	0.000	1.113
	DEC	13.336	0.722	0.000	1.126
	DA Load	0.357	0.041	0.000	0.059
	RT Load	0.733	0.029	0.000	0.076
	Deviation	13.194	0.681	0.000	1.113
West	INC	13.363	0.693	0.000	1.207
	DEC	13.505	0.735	0.000	1.222
	DA Load	0.357	0.041	0.000	0.059
	RT Load	0.731	0.027	0.000	0.077
	Deviation	13.363	0.693	0.000	1.207

Reactive Services Rates

Reactive services charges associated with local voltage support are allocated to real-time load in the control zone or zones where the service is provided. These charges result from uplift payments to units committed by PJM to support reactive/voltage requirements that do not recover their energy offer through LMP payments. These charges are separate from the reactive service capability revenue requirement charges which are a fixed annual charge based on approved FERC filings.[25] Reactive services charges associated with supporting reactive transfer interfaces above 345 kV are allocated daily to real-time load across the entire RTO based on the real-time load ratio share of each network customer.

While reactive services rates are not posted by PJM, a local voltage support rate for each control zone can be calculated and a reactive transfer interface support rate can be calculated for the entire RTO. Table 4-30 shows the reactive services rates associated with local voltage support in 2017 and 2018. Table 4-30 shows that in 2018 the ComEd Control Zone had the highest rate. Real-time load in the ComEd Control Zone paid an average of $0.116 per MWh for reactive services associated with local voltage support, $0.023 or 16.6 percent lower than the average rate paid in 2017.

24 For details about this event see *2018 Quarterly State of the Marker Report for PJM: January through March*, Section 4, "Energy Uplift".

25 See *2018 State of the Marker Report for PJM*, Section 10, "Ancillary Service Markets".

Table 4-30 Local voltage support rates: 2017 and 2018

Control Zone	2017 ($/MWh)	2018 ($/MWh)	Difference ($/MWh)	Percent Difference
AECO	0.000	0.000	(0.000)	(73.2%)
AEP	0.000	0.006	0.006	1,133.8%
APS	0.002	0.000	(0.002)	(100.0%)
ATSI	0.000	0.000	(0.000)	(100.0%)
BGE	0.055	0.001	(0.054)	(98.2%)
ComEd	0.139	0.116	(0.023)	(16.6%)
DAY	0.000	0.000	0.000	0.0%
DEOK	0.000	0.000	0.000	0.0%
DLCO	0.000	0.000	0.000	0.0%
Dominion	0.000	0.000	0.000	39.0%
DPL	0.073	0.014	(0.059)	(81.1%)
EKPC	0.001	0.015	0.014	2,053.7%
JCPL	0.000	0.000	(0.000)	(100.0%)
Met-Ed	0.004	0.000	(0.004)	(100.0%)
OVEC	NA	0.000	NA	NA
PECO	0.002	0.000	(0.002)	(100.0%)
PENELEC	0.099	0.023	(0.076)	(77.1%)
Pepco	0.054	0.000	(0.054)	(100.0%)
PPL	0.000	0.002	0.002	65,601.2%
PSEG	0.000	0.000	(0.000)	(100.0%)
RECO	0.000	0.000	(0.000)	(100.0%)

Balancing Operating Reserve Determinants

Table 4-31 shows the determinants used to allocate the regional balancing operating reserve charges in 2017 and 2018. Total real-time load and real-time exports were 789,165 GWh, 3.7 percent higher in 2018 compared to 2017. Total deviations summed across the demand, supply, and generator categories were 154,706 GWh, 1.9 percent higher in 2018 compared to 2017.

Table 4-31 Balancing operating reserve determinants (GWh): 2017 and 2018

		Reliability Charge Determinants (GWh)			Deviation Charge Determinants (GWh)			
		Real-Time Load	Real-Time Exports	Reliability Total	Demand Deviations (MWh)	Supply Deviations (MWh)	Generator Deviations (MWh)	Deviations Total
2017	RTO	759,025	30,140	789,165	91,907	30,537	29,372	151,816
	East	359,340	11,612	370,953	46,976	17,941	14,149	79,066
	West	399,685	18,528	418,213	44,433	12,292	15,222	71,947
2018	RTO	791,093	27,625	818,718	90,137	28,965	35,603	154,706
	East	374,599	15,791	390,390	44,758	17,047	19,565	81,370
	West	416,495	11,834	428,328	44,722	11,599	16,038	72,360
Difference	RTO	32,068	(2,515)	29,553	(1,770)	(1,572)	6,232	2,890
	East	15,258	4,179	19,437	(2,218)	(894)	5,416	2,304
	West	16,810	(6,694)	10,116	289	(692)	816	413

Deviations fall into three categories, demand, supply and generator deviations. Table 4-32 shows the different categories by the type of transactions that incurred deviations. In 2018, 27.4 percent of all RTO deviations were incurred by participants that deviated due to INCs and DECs or due to combinations of INCs and DECs with other transactions, the remaining 72.6 percent of all RTO deviations were incurred by participants that deviated due to other transaction types or due to combinations of other transaction types. As of November 1, 2018, internal bilateral transactions (IBTs) are no longer used for the calculation of deviations for purposes of allocating balancing operating reserve credits. Given that IBTs were only 0.2 percent of RTO deviations, this will have a negligible impact on balancing operating reserve rates.

Table 4-32 Deviations by transaction type: 2018

Deviation Category	Transaction	Deviation (GWh) RTO	East	West	Share RTO	East	West
Demand	Bilateral Sales Only	307	252	55	0.2%	0.3%	0.1%
	DECs Only	18,954	9,060	9,238	12.3%	11.1%	12.8%
	Exports Only	6,991	4,260	2,731	4.5%	5.2%	3.8%
	Load Only	60,057	29,896	30,161	38.8%	36.7%	41.7%
	Combination with DECs	1,999	790	1,209	1.3%	1.0%	1.7%
	Combination without DECs	1,829	501	1,328	1.2%	0.6%	1.8%
Supply	Bilateral Purchases Only	300	197	104	0.2%	0.2%	0.1%
	Imports Only	7,203	5,109	2,094	4.7%	6.3%	2.9%
	INCs Only	19,912	10,505	9,088	12.9%	12.9%	12.6%
	Combination with INCs	1,492	1,188	304	1.0%	1.5%	0.4%
	Combination without INCs	57	47	10	0.0%	0.1%	0.0%
Generators		35,603	19,565	16,038	23.0%	24.0%	22.2%
Total		154,706	81,370	72,360	100.0%	100.0%	100.0%

Geography of Charges and Credits

Table 4-33 shows the geography of charges and credits in 2018. Table 4-33 includes only day-ahead operating reserve charges and balancing operating reserve reliability and deviation charges since these categories are allocated regionally, while other charges, such as reactive services, synchronous condensing and black start services are allocated by control zone, and balancing local constraint charges are charged to the requesting party.

Charges are categorized by the location (control zone, hub, aggregate or interface) where they are allocated according to PJM's operating reserve rules. Credits are categorized by the location where the resources are located. The shares columns reflect the operating reserve credits and charges balance for each location. For example, transactions in the PPL Control Zone paid 5.4 percent of all operating reserve charges allocated regionally while resources in the PPL Control Zone were paid 1.8 percent of the corresponding credits. The PPL Control Zone received less operating reserve credits than operating reserve charges paid and had 13.1 percent of the deficit. The deficit is the net of the credits and charges paid at a location. Transactions in the BGE Control Zone paid 3.6 percent of all operating reserve charges allocated regionally, and resources in the BGE Control Zone were paid 6.1 percent of the corresponding credits. The BGE Control Zone received more operating reserve credits than operating reserve charges paid and had 9.3 percent of the surplus. The surplus is the net of the credits and charges paid at a location. Table 4-33 also shows that 88.2 percent of all charges were allocated in control zones, 2.9 percent in hubs and aggregates and 8.9 percent in interfaces.

Table 4-33 Geography of regional charges and credits: 2018

Location		Charges (Millions)	Credits (Millions)	Balance	Shares Total Charges	Total Credits	Deficit	Surplus
Zones	AECO	$2.4	$2.7	$0.3	1.3%	1.5%	0.0%	0.7%
	AEP	$24.1	$24.3	$0.2	13.6%	13.7%	0.0%	0.4%
	APS	$9.8	$3.5	($6.3)	5.5%	2.0%	13.1%	0.0%
	ATSI	$12.8	$12.7	($0.2)	7.2%	7.2%	0.3%	0.0%
	BGE	$6.4	$10.8	$4.4	3.6%	6.1%	0.0%	9.3%
	ComEd	$18.2	$20.6	$2.3	10.3%	11.6%	0.0%	4.9%
	DAY	$3.1	$7.5	$4.4	1.8%	4.2%	0.0%	9.2%
	DEOK	$5.5	$2.7	($2.8)	3.1%	1.5%	5.8%	0.0%
	DLCO	$2.6	$0.9	($1.7)	1.5%	0.5%	3.6%	0.0%
	Dominion	$18.1	$27.1	$9.0	10.2%	15.3%	0.0%	19.0%
	DPL	$5.0	$11.6	$6.7	2.8%	6.6%	0.0%	14.0%
	EKPC	$2.3	$4.0	$1.7	1.3%	2.3%	0.0%	3.6%
	External	$0.0	$2.4	$2.4	0.0%	1.3%	0.0%	5.0%
	JCPL	$4.4	$1.7	($2.7)	2.5%	1.0%	5.5%	0.0%
	Met-Ed	$3.5	$1.3	($2.2)	2.0%	0.7%	4.6%	0.0%
	OVEC	$0.0	$0.0	($0.0)	0.0%	0.0%	0.0%	0.0%
	PECO	$7.9	$3.0	($4.9)	4.5%	1.7%	10.1%	0.0%
	PENELEC	$5.8	$6.4	$0.6	3.3%	3.6%	0.0%	1.3%
	Pepco	$6.1	$21.4	$15.3	3.4%	12.1%	0.0%	32.2%
	PPL	$9.6	$3.2	($6.3)	5.4%	1.8%	13.1%	0.0%
	PSEG	$8.4	$8.7	$0.3	4.8%	4.9%	0.0%	0.5%
	RECO	$0.3	$0.0	($0.3)	0.2%	0.0%	0.7%	0.0%
	All Zones	$156.4	$176.5	$20.1	88.2%	99.7%	56.9%	100.0%
Hubs and Aggregates	AEP - Dayton	$0.5	$0.0	($0.5)	0.3%	0.0%	1.1%	0.0%
	Dominion	$0.7	$0.0	($0.7)	0.4%	0.0%	1.5%	0.0%
	Eastern	$0.4	$0.0	($0.4)	0.2%	0.0%	0.9%	0.0%
	New Jersey	$0.4	$0.0	($0.4)	0.2%	0.0%	0.8%	0.0%
	Ohio	$0.2	$0.0	($0.2)	0.1%	0.0%	0.4%	0.0%
	Western Interface	$0.0	$0.0	($0.0)	0.0%	0.0%	0.1%	0.0%
	Western	$2.9	$0.0	($2.9)	1.6%	0.0%	6.0%	0.0%
	RTEP B0328 Source	$0.0	$0.0	($0.0)	0.0%	0.0%	0.0%	0.0%
	All Hubs and Aggregates	$5.1	$0.0	($5.1)	2.9%	0.0%	10.6%	0.0%
Interfaces	CPLE Exp	$0.0	$0.0	($0.0)	0.0%	0.0%	0.1%	0.0%
	CPLE Imp	$0.1	$0.0	($0.1)	0.1%	0.0%	0.2%	0.0%
	Duke Exp	$0.2	$0.0	($0.2)	0.1%	0.0%	0.4%	0.0%
	Duke Imp	$0.2	$0.0	($0.2)	0.1%	0.0%	0.4%	0.0%
	Hudson	$0.3	$0.0	($0.3)	0.2%	0.0%	0.6%	0.0%
	IMO	$1.5	$0.0	($1.5)	0.8%	0.0%	3.1%	0.0%
	Linden	$0.4	$0.0	($0.4)	0.2%	0.0%	0.9%	0.0%
	MISO	$3.4	$0.0	($3.4)	1.9%	0.0%	7.1%	0.0%
	NCMPA Imp	$0.2	$0.0	($0.2)	0.1%	0.0%	0.4%	0.0%
	Neptune	$0.5	$0.0	($0.5)	0.3%	0.0%	1.0%	0.0%
	NIPSCO	$0.1	$0.0	($0.1)	0.1%	0.0%	0.2%	0.0%
	Northwest	$0.2	$0.0	($0.2)	0.1%	0.0%	0.5%	0.0%
	NYIS	$1.5	$0.0	($1.5)	0.8%	0.0%	3.0%	0.0%
	South Exp	$2.7	$0.0	($2.7)	1.5%	0.0%	5.6%	0.0%
	South Imp	$4.3	$0.0	($4.3)	2.4%	0.0%	9.0%	0.0%
	All Interfaces	$15.7	$0.5	($15.2)	8.9%	0.3%	32.5%	0.0%
	Total	$177.2	$177.0	($0.2)	100.0%	100.0%	100.0%	100.0%

Energy Uplift Issues

Intraday Segments Uplift Settlement

PJM pays uplift separately for multiple segmented blocks of time during the operating day (intraday).[26] The use of intraday segments to calculate the need for uplift payments results in higher uplift payments than necessary to make units whole, including uplift payments to units that are profitable on a daily basis. The MMU recommends eliminating intraday segments from the calculation of uplift payments and returning to calculating the need for uplift based on the entire 24 hour operating day.

Table 4-34 shows balancing operating reserve credits calculated using intraday segments and balancing operating reserve payments calculated on a daily basis. In 2017, balancing operating reserve credits would have been $8.3 million or 12.7 percent lower if they were calculated on a daily basis. In 2018, balancing operating reserve credits would have been $21.9 million or 24.3 percent lower if they were calculated on a daily basis.

Table 4-34 Intraday segments and daily balancing operating reserve credits: 2017 and 2018

	2017 BOR Credits (Millions)			2018 BOR Credits (Millions)		
	Intraday Segments Calculation	Daily Calculation	Difference	Intraday Segments Calculation	Daily Calculation	Difference
Jan	$7.0	$6.7	($0.3)	$33.1	$27.1	($6.1)
Feb	$1.2	$1.1	($0.1)	$1.8	$1.3	($0.4)
Mar	$4.3	$3.8	($0.5)	$3.0	$2.2	($0.8)
Apr	$2.3	$1.9	($0.4)	$5.6	$4.1	($1.5)
May	$5.4	$4.6	($0.8)	$5.8	$3.6	($2.2)
Jun	$3.8	$3.3	($0.5)	$2.7	$1.5	($1.2)
Jul	$5.6	$4.3	($1.3)	$7.4	$5.0	($2.4)
Aug	$4.7	$4.1	($0.6)	$7.2	$5.1	($2.1)
Sep	$8.2	$6.8	($1.4)	$9.5	$7.0	($2.5)
Oct	$7.0	$6.3	($0.7)	$6.2	$4.7	($1.4)
Nov	$6.1	$5.5	($0.5)	$6.3	$5.3	($1.0)
Dec	$9.7	$8.6	($1.0)	$1.6	$1.3	($0.3)
Total	$65.3	$57.0	($8.3)	$90.2	$68.3	($21.9)

Prior to April 1, 2018, for purposes of calculating LOC credits, each hour was defined as a unique segment. Following the implementation of five minute settlements on April 1, 2018, LOC credits are calculated with each five minute interval defined as a unique segment. Thus a profit in one five minute segment, resulting from the real-time LMP being lower than the day-ahead LMP, is not used to offset a loss in any other five-minute segment. This change in settlements causes an increase in LOC credits compared to hourly settlement as generators are made whole for any losses incurred in a five minute interval while previously gains and losses were netted across the hour. Table 4-35 shows the impact of changing the settlements of day-ahead LOC credits from an hourly basis to a five minute basis. For the months of April through December 2018, day-ahead LOC credits would have been $2.1 million or 11.3 percent lower had they been settled on an hourly basis compared to being settled on a five minute basis.

Table 4-35 Five minute settlement and hourly settlement of day-ahead lost opportunity cost credits: April through December, 2018

	2018 Day Ahead LOC Credits (Millions)		
	Five Minute Settlement	Hourly Settlement	Difference
Apr	$2.0	$1.9	($0.1)
May	$6.0	$5.5	($0.5)
Jun	$3.5	$3.0	($0.5)
Jul	$2.1	$1.8	($0.3)
Aug	$1.7	$1.6	($0.2)
Sep	$2.2	$2.1	($0.2)
Oct	$1.9	$1.7	($0.2)
Nov	$0.5	$0.5	($0.0)
Dec	$0.7	$0.6	($0.1)
Total	$20.7	$18.6	($2.1)

26 See PJM "Manual 28: Operating Reserve Accounting," Rev. 81 (October 25, 2018).

Table 4-36 shows day-ahead LOC credits calculated using intraday segments and LOC credits calculated on a daily basis. In 2017, LOC credits would have been $1.8 million or 18.2 percent lower if they were calculated on a daily basis. In 2018, LOC credits would have been $8.7 million or 23.2 percent lower if they were calculated on a daily basis.

Table 4-36 Five minute settlement and daily settlement of lost opportunity cost credits: 2017 and 2018

	2017 Day Ahead LOC Credits (Millions)			2018 Day Ahead LOC Credits (Millions)		
	Intraday Segments Calculation	Daily Calculation	Difference	Intraday Segments Calculation	Daily Calculation	Difference
Jan	$0.1	$0.1	($0.0)	$13.7	$11.0	($2.8)
Feb	$0.1	$0.0	($0.0)	$0.1	$0.1	($0.0)
Mar	$0.9	$0.7	($0.2)	$3.1	$2.6	($0.5)
Apr	$0.5	$0.3	($0.1)	$2.0	$1.3	($0.7)
May	$0.8	$0.7	($0.1)	$6.0	$4.7	($1.3)
Jun	$0.7	$0.6	($0.1)	$3.5	$2.3	($1.3)
Jul	$1.5	$1.3	($0.2)	$2.1	$1.5	($0.6)
Aug	$0.5	$0.4	($0.1)	$1.7	$1.4	($0.4)
Sep	$1.5	$1.3	($0.2)	$2.2	$1.7	($0.5)
Oct	$0.8	$0.6	($0.2)	$1.9	$1.4	($0.4)
Nov	$0.5	$0.3	($0.2)	$0.5	$0.4	($0.1)
Dec	$2.3	$1.9	($0.4)	$0.7	$0.5	($0.2)
Total	$10.1	$8.3	($1.8)	$37.7	$28.9	($8.7)

Closed Loop Interfaces

PJM implemented closed loop interfaces with the stated purpose of improving the incorporation of reactive constraints into energy prices and to allow emergency DR to set price.[27] PJM applies closed loop interfaces so that it can use units needed for reactive support to set the energy price when they would not otherwise set price under the LMP algorithm. PJM also applies closed loop interfaces so that it can use emergency DR resources to set the real-time LMP when DR resources would not otherwise set price under the fundamental LMP logic. Of the 20 closed loop interface definitions, 11 (55 percent) were created for the purpose of allowing emergency DR to set price.

Closed loop interfaces are used to model the transfer capability into a specific area. Areas or regions are defined in PJM by hubs, aggregates or control zones, all comprised of buses. Closed loop interfaces are not defined by buses, but defined by the transmission facilities that connect the buses inside the loop with the rest of PJM. When PJM wants a closed loop interface to bind, PJM reduces the capacity of the transmission facilities to a level that will artificially make marginal the resource selected by PJM. Table 4-37 shows the closed loop interfaces that PJM has defined and PJM's objective in defining each closed loop interface.

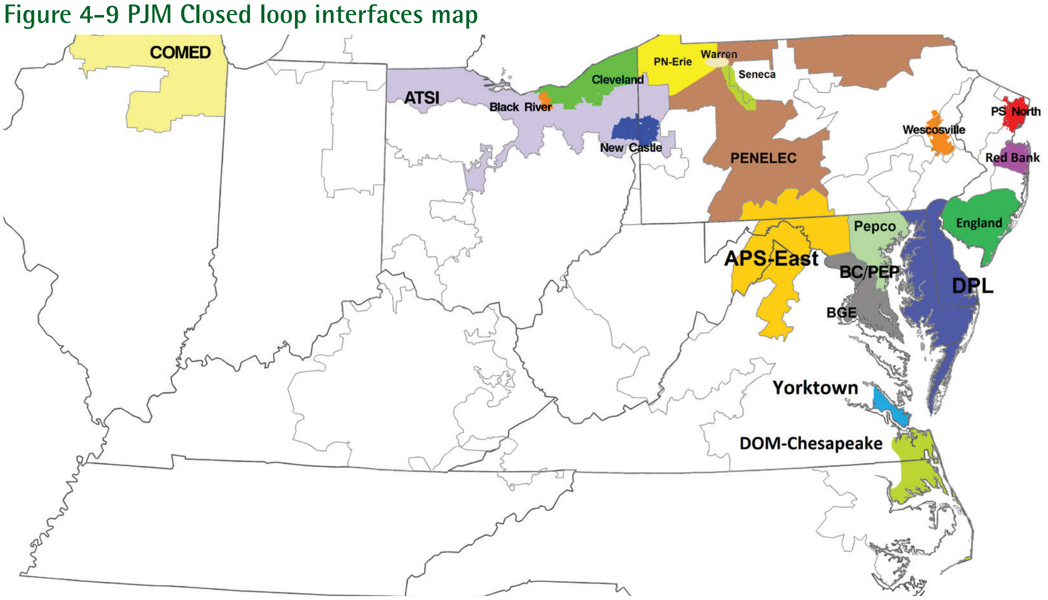
27 See PJM/Alstom. "Approaches to Reduce Energy Uplift and PJM Experiences," presented at the FERC Technical Conference: Increasing Real-Time and Day-Ahead Market Efficiency Through Improved Software in Docket No. AD10-12-006 <http://www.ferc.gov/june-tech-conf/2015/presentations/m2-3.pdf> (June 23, 2015).

Table 4-37 PJM closed loop interfaces[28 29 30]

Interface	Control Zone(s)	Objective	Effective Date	Limit Calculation
APS-East	APS	Allow emergency DR resources / unit(s) needed for reactive to set real-time LMP	June 19, 2015	Limit equal to actual flow
ATSI	ATSI	Allow emergency DR resources / unit(s) needed for reactive to set real-time LMP	July 17, 2013	Limit equal to actual flow
BC	BGE	Allow emergency DR resources / unit(s) needed for reactive to set real-time LMP	June 19, 2015	Limit equal to actual flow
BC/PEP	BGE and Pepco	Reactive Interface (not an IROL). Used to model import capability into the BGE/PEPCO/Doubs/Northern Virginia area	NA	PJM Transfer Limit Calculator
Black River	ATSI	Allow emergency DR resources to set real-time LMP	September 1, 2014	Limit equal to actual flow
Cleveland	ATSI	Reactive Interface (IROL)	NA	PJM Transfer Limit Calculator
COMED	ComEd	Reactive Interface (IROL)	NA	PJM Transfer Limit Calculator
DOM-Chesapeake	Dominion	Allow emergency DR resources / unit(s) needed for reactive to set real-time LMP	August 14, 2015	Limit equal to actual flow
DPL	DPL	Allow emergency DR resources / unit(s) needed for reactive to set real-time LMP	June 19, 2015	Limit equal to actual flow
England	AECO	Allow emergency DR resources / unit(s) needed for reactive to set real-time LMP	June 1, 2017	Limit equal to actual flow
New Castle	ATSI	Allow emergency DR resources to set real-time LMP	July 1, 2014	Limit equal to actual flow
PENELEC	PENELEC	Allow emergency DR resources / unit(s) needed for reactive to set real-time LMP	April 22, 2015	Limit equal to actual flow
Pepco	Pepco	Allow emergency DR resources / unit(s) needed for reactive to set real-time LMP	June 19, 2015	Limit equal to actual flow
PL-Wescosville	PPL	Allow emergency DR resources / unit(s) needed for reactive to set real-time LMP	July 24, 2014	Limit equal to actual flow
PN-Erie	PENELEC	Allow emergency DR resources to set real-time LMP	April 22, 2015	Limit equal to actual flow
PS North	PSEG	Objective not identified. Interface was modeled in 2014/2015 Annual FTR auction	NA	NA
Red Bank	JCPL	Allow emergency DR resources / unit(s) needed for reactive to set real-time LMP	June 1, 2017	Limit equal to actual flow
Seneca	PENELEC	Allow unit(s) needed for reactive to set day-ahead and real-time LMP	February 1, 2014	Limit equal to actual flow
Warren	PENELEC	Allow unit(s) needed for reactive to set day-ahead and real-time LMP	September 26, 2014	Limit equal to actual flow
Yorktown	Dominion	Allow unit(s) needed for reactive to set day-ahead and real-time LMP	April 1, 2017	Limit equal to actual flow

Figure 4-9 shows the approximate geographic location of PJM's closed loop interfaces.

Figure 4-9 PJM Closed loop interfaces map



28 See PJM. "Manual 3: Transmission Operations," Rev. 48 (Dec. 1, 2015) for a description of reactive interfaces.
29 See closed loop interfaces definitions at <http://www.pjm.com/markets-and-operations/etools/oasis/system-information.aspx>.
30 See the PS North interface definition at <http://www.pjm.com/pub/account/auction-user-info/model-annual/Annual-PJM-interface-definitions-limits.csv>.

PJM's uses closed loop interfaces to artificially allow the strike price of emergency DR to set LMP. This use of closed loop interfaces permits subjective price setting by PJM. PJM has not explained why the economic fundamentals require that DR strike prices set LMP when the resource is not marginal. Although DR should be nodal, DR is not nodal and cannot routinely set price in an LMP model. The MMU has recommended that DR be nodal so that it can set price when appropriate. The current PJM rules permit emergency DR to set a strike price as high as $1,849. There are no incentives for DR to set strike prices at an economically rational level because emergency DR is guaranteed the payment of its strike price whenever called. The MMU has recommended that emergency DR have an offer cap no higher than generation resources, that emergency DR be required to make offers in the Day-Ahead Energy Market like other capacity resources and the emergency DR be paid LMP rather than a guaranteed strike price when called on. PJM's use of closed loop interfaces is a result of significant deficiencies in the rules governing DR. PJM's use of closed loop interfaces is also result of significant issues with PJM's scarcity pricing model which is not adequately locational. PJM uses closed loop interfaces and emergency DR strike prices as a substitute for improved, more locational scarcity pricing.

In a DC power flow model, such as the one used by PJM for dispatch and pricing, units scheduled for reactive support are only marginal when they are needed to supply energy above their economic minimum. With the use of closed loop interface, these units are forced to be marginal in the model even when not needed for energy, by adjusting the limit of the closed loop interface. This artificially creates congestion in the area that can only be relieved by the units providing reactive support inside the loop. The goal is to reduce energy uplift from the noneconomic operation of units needed for reactive support by forcing these units to be marginal when they are not, raising energy prices and thereby reducing uplift.[31]

The MMU has recommended and supports PJM's goal of having dispatcher decisions reflected in transparent market outcomes, preferably LMP, to the maximum extent possible and to minimize the level and rate of energy uplift charges. But part of that goal is to avoid distortion of the way in which the transmission network is modeled. The use of closed loop interfaces is a distortion of the model.

The MMU recommends that PJM not use closed loop interface constraints to artificially override the nodal prices that are 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.

Market prices should be a function of market fundamentals and energy market prices should be a function of energy market fundamentals. PJM has not explained why the other consequences of deviating from market fundamentals do not outweigh any benefits of artificially creating constraints in order to let reactive resources set price when they are not in fact marginal. PJM has not explained why the use of closed loop interfaces to permit emergency DR to set price is not simply a crude workaround to a viable solution, consistent with the LMP model, which would be to make DR nodal. The need for closed loop interfaces to let emergency DR set price is primarily a result of the fact that DR is zonal, or subzonal with one day's notice, and therefore cannot be dispatched nodally or set price nodally. With full implementation of the Capacity Performance market starting in the 2020/2021 Delivery Year, PJM will be able to dispatch DR within a PAI area, by only by guessing the DR connected to the each node. The reduction of uplift is a reasonable goal in general, but the reduction of uplift is not a goal that justifies creating distortions in the price setting mechanism.

CT Price Setting Logic

In November 2014, PJM implemented a software change to its day ahead and real time market solution tools that would enable PJM to reduce energy uplift by artificially selecting the marginal unit for any constraint. The goal is to make marginal any unit committed by PJM to provide reactive services, black start or transmission constraint relief if such unit would otherwise run with an incremental offer greater than the correctly calculated LMP. PJM calls this approach price setting logic.

31 See "PJM Price-Setting Changes," presented to the EMUSTF at <http://www.pjm.com/~/media/committees-groups/task-forces/emustf/20131220/20131220-item-02c-price-setting-option.ashx>.

The application of the price setting logic reduces energy uplift payments by artificially increasing the LMP. The price setting logic is a form of subjective pricing because it varies from fundamental LMP logic based on an administrative decision to reduce energy uplift.

PJM and Alstom presented examples of this approach at the FERC Technical Conference, "Increasing Real-Time and Day-Ahead Market Efficiency Through Improved Software."[32] The presentation shows a two bus model connected by one transmission line, three generators (A, B and C) and load at one of the buses. Solution 1: In the solution based on the fundamental LMP logic that PJM has used since the inception of markets, two of the generators are committed (A at 50 MW and B at 50 MW) to serve load (100 MW). The LMP is set at $50 per MWh (the offer of generator A) at both buses. Generator B has to be made whole (paid energy uplift) because the LMP ($50 per MWh) does not cover the generator's offer ($100 per MWh). Generator B does not set the LMP because its economic minimum is higher than the relief needed to relieve the constraint. This solution is not acceptable for PJM because the most expensive generator would have to be made whole. In order to reduce energy uplift, PJM shows two alternatives. Solution 2: Artificially redefine the economic minimum of generator B to zero MW. Solution 3: Artificially redefine the limit of the transmission line to a level that would make the LMP higher at the bus where the most expensive generator is connected.

In solution 2, generator B is dispatched at 10 MW, despite the fact that this is physically impossible. This allows generator A to increase its output to 80 MW, which makes the transmission constraint binding and causes price separation between the two buses. This is an artificial result, not consistent with actual dispatch, designed to achieve an administrative goal.

In solution 3, the line limit is reduced from 80 MW to 40 MW, despite the fact that this is not the actual limit. As a result, generator A is dispatched to 40 MW (10 MW less than the original solution), the transmission line constraint is binding and congestion occurs. The goal is met and energy uplift is reduced to zero because the LMPs at both buses are increased so that they equal or exceed the generators' offers. Again, this is an artificial result, not consistent with actual dispatch, designed to achieve an administrative goal.

Attempting to reduce uplift at the expense of fundamental LMP logic is not consistent with the objective of clearing the market using a least cost approach. The result of PJM's price setting logic in this example is to increase total production costs.

The MMU recommends that PJM not use price setting logic to artificially override the nodal prices that are based on fundamental LMP logic in order to reduce uplift.

The MMU supports efforts to ensure that LMP reflects the appropriate marginal resource. The MMU recommends that if PJM believes it appropriate to use CT price setting logic, PJM initiate a stakeholder process to create transparent and consistent modifications to the rules and incorporate the modifications in the PJM tariff.

Energy Uplift Recommendations

Recommendations for Calculation of Credits

Day-Ahead Operating Reserve Elimination

The only reason to pay energy uplift in the Day-Ahead Energy Market is that a day-ahead schedule could cause a unit to incur losses as a result of differences between the Day-Ahead and Balancing Markets. Units cannot incur losses in the Day-Ahead Energy Market. Units do not incur costs in the Day-Ahead Energy Market. There is no reason to pay energy uplift in the Day-Ahead Energy Market. All energy uplift should be paid in real time including energy uplift that results from differences between day-ahead and real-time schedules. Paying energy uplift in the Day-Ahead Energy Market results in overpayments.

Day-ahead operating reserve credits are paid to market participants under specific conditions in order to ensure that units are not scheduled in the Day-Ahead Energy Market by PJM to operate at a loss in real time. Balancing operating reserve credits are paid to market participants under specific conditions in order to ensure that units are not operated by PJM at a loss in real time. Units

32 See PJM/Alstom. "Approaches to Reduce Energy Uplift and PJM Experiences," presented at the FERC Technical Conference: "Increasing Real-Time and Day-Ahead Market Efficiency Through Improved Software," in Docket No. AD10-12-006 <http://www.ferc.gov/june-tech-conf/2015/presentations/m2-3.pdf> (June 23, 2015).

are paid day-ahead operating reserve credits whenever their total offer (including no load and startup costs and based on their day-ahead scheduled output) is not covered by the day-ahead energy revenues (day-ahead LMP times day-ahead scheduled output). Units are paid balancing operating reserve credits whenever their total offer (including no load and startup costs and based on their real-time output) are not covered by their day-ahead energy revenues, balancing energy revenues and a subset of net ancillary services revenues.[33]

Units scheduled in the Day-Ahead Energy Market do not operate until committed or dispatched in real time. Therefore, it cannot be determined if a unit was operated at a loss until the unit actually operates or does not operate. The current operating reserve rules governing the day-ahead operating reserve credits assume that units are going to operate exactly as scheduled because they are made whole based on their day-ahead scheduled output. A unit's real-time output may be greater or lower than their day-ahead scheduled output. Units dispatched in real time by PJM above their day-ahead scheduled output could be paid energy uplift in the form of balancing operating reserve credits if by increasing their output they operate at a loss because their offers are greater than the real-time LMP. Units dispatched in real time by PJM below their day-ahead scheduled output could be paid energy uplift in the form of balancing operating reserve credits if by decreasing their output the units operate at a loss or incur opportunity costs because real-time LMP is greater than the day-ahead LMP. The balancing operating reserve credits and lost opportunity costs credits ensure that units recover their total offers or keep their net revenues in real time.

Units scheduled in the Day-Ahead Energy Market that receive day-ahead operating reserve credits and for which real-time operation results in additional losses, are paid energy uplift in the form of balancing operating reserve or lost opportunity cost credits to ensure that they do not operate at a loss. This determination is not symmetrical because units scheduled in the Day-Ahead Energy Market that receive day-ahead operating reserve credits and for which real-time operation results in reduced losses or no loss do not have a reduction in energy uplift payments.

33 The balancing operating reserve credit calculation includes net DASR revenues, net synchronized reserve revenues, net nonsynchronized reserve revenues and reactive services revenues.

Units that follow PJM dispatch instructions are made whole through operating reserve credits to ensure that they do not operate at a loss. In order to determine if a unit operated at a loss, it needs to be committed or dispatched. The day-ahead scheduled output is one of PJM's dispatch instructions, but it does not determine if a unit actually operated at a loss. In order to determine if a unit operated at a loss it is necessary to take into account the unit's real-time output and both the day-ahead and balancing energy revenues and ancillary services net revenues.

In order to properly compensate units, the MMU recommended enhancing the day-ahead operating reserve credits calculation to ensure that units receive an energy uplift payment based on their real-time output and not their day-ahead scheduled output whenever their real time operation results in a lower loss or no loss at all. The MMU also recommended including net DASR revenues as part of the offsets used in determining day-ahead operating reserve credits.[34] These recommendations are superseded by the MMU's recommendation to eliminate day-ahead operating reserve payments.[35] The elimination of day-ahead operating reserve payments also ensures that units are always made whole based on their actual operation and actual revenues.

The MMU calculated the impact of this recommendation for 2018. Energy uplift cost associated with units scheduled in the Day Ahead Energy Market would have been reduced by $12.1 million or 28.3 percent ($9.6 million paid as day ahead operating reserves and $2.5 million paid as reactive service credits).

The elimination of the day-ahead operating reserve category would change the allocation of such charges under the current energy uplift rules. If the day-ahead operating reserve category were eliminated but the MMU's uplift allocation recommendations were not implemented, units that clear the Day-Ahead Energy Market would be made whole through balancing operating reserve credits, which under the current rules are allocated to deviations or real-time load plus real-

34 See *2013 State of the Market Report for PJM*, Volume 2 Section 4: "Energy Uplift," at "Day-Operating Reserve Credits," and at "Net DASR Revenues Offset" for an explanation of these recommendations.

35 PJM agrees with this recommendation. See "Explanation of PJM Proposals," from the Energy Market Uplift Senior Task Force (April 30, 2014). <http://www.pjm.com/~/media/committees-groups/task-forces/emustf/20140417/20140417-explanation-of-pjm-proposals.ashx>.

time exports. Therefore, this recommendation should be implemented concurrently with the MMU's allocation recommendations.

Net Regulation Revenues Offset

On October 1, 2008, PJM filed revisions to the Operating Agreement and Tariff with FERC related to the PJM Regulation Market. The filing included four elements: implement the TPS test in the PJM Regulation Market; increase the regulation offer adder from $7.50 per MW to $12.00 per MW; eliminate the use of net regulation revenues as an offset in the balancing operating reserve calculation; and calculate the lost opportunity cost on the lower of a unit's price-based or cost-based offer. The four elements were based on a settlement rather than a rational evaluation of an efficient market design.

The elimination of the use of net regulation revenues as an offset in the balancing operating reserve calculation had a direct impact on the level of energy uplift paid to participants that regulate while operating as noneconomic. The result of not using the net regulation revenues as an offset in the balancing operating reserve credit calculation is that PJM does not accurately calculate whether a unit is running at a loss. PJM procures energy, regulation, synchronized and nonsynchronized reserves in a jointly optimized manner. PJM determines the mix of resources that could provide all of those services in a least-cost manner. Excluding the net regulation revenues from the balancing operating reserve credit calculation is inconsistent with the process used by PJM to procure these services and inconsistent with the basic PJM uplift logic. Whether a unit is running for PJM at a loss defined by marginal costs cannot be determined if some of the revenues are arbitrarily excluded.

Another issue related to this exclusion is the treatment of pool-scheduled units that elect to self-schedule a portion of their capacity for regulation. A unit can be pool-scheduled for energy, which means PJM may commit or dispatch the unit based on economics, but it can also self-schedule some of its capacity for regulation. When this happens the capacity self-scheduled for regulation is treated as a price taker, but in the energy market any increase in MW to provide regulation are treated as additional costs, which can result in increased balancing operating reserve credits whenever the real-time LMP is lower than the unit's offer. For example, if a unit raises its economic minimum in order to provide regulation and the additional costs resulting from operating at a higher economic minimum are not covered by the real-time LMP, the unit will be made whole for the additional costs through balancing operating reserve credits.

The MMU recommends reincorporating the use of net regulation revenues as an offset in the calculation of balancing operating reserve credits. In 2018, using net regulation revenues as an offset in the balancing operating reserve calculation would have resulted in a net decrease of balancing operating reserve charges of $0.9 million.

Self Scheduled Start

Participants may offer their units as pool-scheduled (economic) or self-scheduled (must run).[36] Units offered as pool-scheduled clear the Day-Ahead Energy Market based on their offers and operate in real time following PJM dispatch instructions. Units offered as self-scheduled clear the Day-Ahead Energy Market regardless of their offers and may operate in real time following PJM dispatch instructions. Units offered as self-scheduled follow PJM dispatch instructions when they are offered with a minimum must run output from which the units may be dispatched up but not down. Self-scheduled units are not eligible to receive day-ahead or balancing operating reserve credits. The current rules determine if a unit is pool-scheduled or self-scheduled for operating reserve credits purposes separately for each hour using the hourly commitment status flag. If the flag is set as economic the unit is assumed to be pool-scheduled, if the flag is set as must run the unit is assumed to be self-scheduled. When a unit submits different flags within a day, the day-ahead operating reserve credit calculation treats each group of hours separately. The day-ahead operating reserve credit calculation only uses the hours flagged as economic and excludes any hours flagged as must run.

Units offered as self-scheduled for some hours of the day and pool-scheduled for the remaining hours are made whole for startup costs when they should not be. For example, if a unit is offered as self-scheduled for hours 10 through 24 and as pool-scheduled for the balance of the day and PJM selects the unit to start for

36 See "PJM eMkt Users Guide," Managing Unit Data (July 9, 2015) p. 42. <http://www.pjm.com/~/media/etools/emkt/ts-userguide.ashx>.

hour nine, the unit will be made whole for its startup cost if the hourly revenues do not cover the costs. The only hour used in the day-ahead or balancing operating reserve credit calculation is hour nine because the unit is not eligible for operating reserve credits for hours 10 through 24. The result is that any net revenue from hours 10 through 24 will not be used to offset the unit's startup cost despite the fact that the unit would have started and incurred those costs regardless of PJM dispatch instructions.

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.

Lost Opportunity Cost Calculation

The current energy LOC calculations are inaccurate and create unreasonable compensation. The MMU recommended four modifications, of which three were adopted on September 1, 2015.[37] [38] The one outstanding modification not adopted by PJM is the calculation of LOC using segments of hours. Current rules calculate LOC on an interval basis; each interval is treated as a standalone calculation. This means that units receive an LOC payment during intervals in which it is economic for them to run and receive the benefit of not being called on during intervals in which it is not economic for them to run. PJM dispatchers might make the right decision to not call a unit in real time because the operation of the unit during all the hours in which the unit cleared the Day-Ahead Energy Market would not be economic, but the unit could still receive an LOC payment.

This is inconsistent with the basic PJM energy uplift logic. If a unit does not run in real time, it loses net revenues if the real-time LMP is greater than the unit's offer but it gains net revenues if the real-time LMP is lower than the unit's offer. The correct lost opportunity costs for units that clear the Day-Ahead Energy Market and are not committed in real time cannot be determined if profitable intervals are arbitrarily excluded. In the case of separate interval calculations, units are overcompensated compared to the net revenues they would have received had they run.

37 See *2015 State of the Market Report for PJM*, Volume 2 Section 4, "Energy Uplift," at "Lost Opportunity Cost Calculation" for an explanation of the adopted recommendations.
38 152 FERC ¶ 61,165 (2015)

The MMU recommends calculating LOC based on 24 hour daily periods for combustion turbines and diesels scheduled in the Day-Ahead Energy Market but not committed in real time. This recommendation has not been adopted. The MMU calculated the impact of this recommendation for 2018. In 2018, lost opportunity cost payments would have had been reduced by $8.7 million or 23.2 percent.

In addition to the initial four recommendations, the MMU recommends two additional steps to address issues with the current LOC calculations:

- **Achievable Output:** CTs and diesels are compensated for LOC when scheduled in the Day-Ahead Energy Market and not committed in real time. This LOC calculation uses the day-ahead scheduled output as the achievable output for which units are entitled to receive LOC compensation. Units are paid LOC based on the difference between the real-time energy price (RT LMP) and the unit's offer times the day-ahead scheduled output.

  The actual LOC is a function of the real-time desired and achievable output rather than the day-ahead scheduled output. If a unit is capable of profitably producing more or fewer MWh in real time than the day-ahead scheduled MWh, it is the actual foregone MWh in real time that define actual LOC. Also, if a unit is not capable of producing at the day-ahead scheduled output level in real time it should not be compensated based on an output that cannot be achieved.

  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.

- **LOC Unit Type Eligibility:** The current rules compensate only CTs and diesels for LOC when scheduled in the Day-Ahead Energy Market and not committed in real time. The reason for this difference is that other unit types have a commitment obligation when scheduled in the Day-Ahead Energy Market. For example, steam turbines and combined cycle units commitment instructions are their day-ahead schedule. Units of these types that clear the Day-Ahead Energy Market are automatically committed to be on or remain on in real time. These units are eligible for LOC compensation only if PJM explicitly cancels their day-ahead commitment for reliability purposes. CT and diesel commitment instructions occur in real time even if these units were committed in the Day-Ahead Energy Market. CTs and diesels are committed in real time, after PJM dispatch has a more complete knowledge of real-time conditions. The goal is to permit the dispatch of flexible units in real time based on real-time conditions as they evolve. The reason for this special treatment of CTs and diesels is that historically, such units were usually more flexible to commit than other unit types. But that is no longer correct and should not be assumed to be correct.

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 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.

Following Dispatch

PJM's method to determine whether a unit is following dispatch is fundamentally flawed. PJM does not currently have the ability to automatically monitor, identify, and measure whether generators are following dispatch. As a result, uplift eligibility is not determined correctly, generator deviations are calculated incorrectly and uplift credits are paid incorrectly.

PJM calculates the difference between units' output and units' ramp limited desired output for every five minute interval.[39] A unit is considered to be following dispatch if the difference is less than ten percent. Units that are considered to be following dispatch are not assessed any generator deviations.

PJM's following dispatch metric is incorrect for two reasons. The ramp limited desired output is based on the unit's generation during the prior five minute interval. The maximum deviation that unit can be assessed is limited to the unit's ramp rate over five minutes. For example, if the unit is operating at 500 MW and receives a dispatch down signal but remains at 500 MW for the first interval, the ramp limited desired output for the next interval will continue to be based on the 500 MW output level. This will continue without limit. For many units the ramp rate is low enough that the difference always remains below the ten percent threshold. The ramp rate for each unit used to calculate the ramp limited desired output is continuously adjusted by PJM based on the unit's performance, using a metric known as degree of generator performance (DGP). If a unit is either not responding to the dispatch signal or moving slower than its offered ramp rate, its desired output will be adjusted accordingly and the unit will be deemed to be following dispatch by definition. As a result, the following dispatch metric is not a meaningful basis for assessing whether units are following dispatch. For some units, it is impossible to fail the tests.

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.

Fast start resources, which include combustion turbines and diesels, are simply exempt from the following dispatch calculation.[40] As a result, these resources are considered to always be following dispatch, by definition. The MMU recommends that this exemption be eliminated and that all resources be evaluated with a meaningful following dispatch metric.

Quantifiable Impact of Recommendations

Table 4-38 shows the impact of the highest impact recommendations for the calculation of uplift credits. The recommendations include: the elimination of day-ahead credits; the inclusion of regulation offsets in the calculation of balancing operating reserve credits; and calculating the need for balancing operating reserve credits and LOC credits on a daily basis. The implementation of these recommendations combined would have reduced uplift credits by $47.4 million or 23.8 percent of all uplift credits in 2018.

39 For details see OATT § 3.2.3(o).

40 PJM defines fast start resources as resources with startup plus notification time of 2 hours or less and a minimum run time of 2 hours or less. See "PJM Manual 28: Operating Agreement Accounting," Rev. 81 (Oct. 25, 2018)

Table 4-38 Current and proposed energy uplift credits (millions)

Proposal	Credits Impacted	Current Credits (millions)	Proposal Credits (millions)	Difference (millions)
Eliminate day-ahead operating reserve credits	Day-ahead generator Day-ahead reactive	$45.8	$32.9	($12.9)
Include regulation offsets in the calculation of balancing operating reserves	Balancing operating reserve Local constraint Reactive	$100.1	$99.1	($0.9)
Calculate the need for balancing credits on a daily basis	Balancing operating reserve Local constraint Reactive	$100.1	$78.3	($21.8)
Calculate lost opportunity cost credits on a daily basis	Day-ahead LOC	$37.7	$28.9	($8.8)
Total combined impact of elimination of day-ahead credits, adding regulation offsets, and calculating balancing credits and day-ahead LOC credits on a daily basis	Day-ahead generator Day-ahead reactive Balancing operating reserve Day-ahead LOC	$183.6	$136.2	($47.4)

Recommendations for Allocation of Uplift Charges

Up to Congestion Transactions

Up to congestion transactions do not pay energy uplift charges. An up to congestion transaction affects unit commitment and dispatch in the same way that increment offers and decrement bids affect unit commitment and dispatch in the Day-Ahead Energy Market. All such virtual transactions affect the results of the Day-Ahead Energy Market and contribute to energy uplift costs. Up to congestion transactions are currently receiving preferential treatment, relative to increment offers and decrement bids and other transactions because they are not charged 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.

The MMU calculated the impact on energy uplift rates if up to congestion transactions had paid energy uplift charges based on deviations in the same way that increment offers and decrement bids do. Table 4-39 shows the current average uplift rates for a 1 MW transaction and the average rates based on the proposed UTC uplift allocation. Two scenarios are presented, one assuming 100 percent of the 2018 UTC volume, and the other assuming 50 percent of the 2018 UTC volume. At 100 percent of the UTC volume a UTC would have paid on average between $0.489 and $0.500 per UTC MW. At 100 percent UTC volume UTC transactions would have paid $5.1 million in day-ahead uplift charges and $69.4 million in balancing deviation charges. At 50 percent UTC volume UTC transactions would have paid $2.8 million in day-ahead uplift charges and $52.0 million in balancing deviation charges.

Table 4-39 Current and proposed operating reserve rates ($/MWh): 2018

	Transaction	Current Average Rates	Average Rates with Proposed UTC Uplift Allocation (100% UTC Volume)	Average Rates with Proposed UTC Uplift Allocation (50% UTC Volume)
East	INC	0.681	0.233	0.347
	DEC	0.722	0.268	0.384
	DA Load	0.041	0.035	0.038
	RT Load	0.029	0.029	0.029
	Deviation	0.681	0.233	0.347
West	INC	0.693	0.227	0.342
	DEC	0.735	0.262	0.379
	DA Load	0.041	0.035	0.038
	RT Load	0.027	0.027	0.027
	Deviation	0.693	0.227	0.342
UTC	East to East	NA	0.500	0.731
	West to West	NA	0.489	0.721
	East to/from West	NA	0.495	0.726

Day-Ahead Reliability Energy Uplift Allocation

PJM may schedule units as must run in the Day-Ahead Energy Market when needed in real time to address reliability issues in four categories: voltage issues (high and low); black start requirements (from automatic load rejection units); local contingencies not modeled in the Day-Ahead Energy Market; and long lead time units not able to be scheduled in the Day-Ahead Energy Market.[41] The energy uplift paid to units scheduled for voltage is allocated to real-time load. The energy uplift associated with units scheduled for black start is allocated to real-time load and interchange reservations. The energy uplift paid to units scheduled because of local contingencies not modeled in the Day-Ahead Energy Market and scheduled because of their long lead times is allocated to day-ahead demand, day-ahead exports and decrement bids.

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.

Reactive Services Credits and Balancing Operating Reserve Credits

Energy uplift credits to resources providing reactive services are separate from balancing operating reserve credits.[42] Under the current rules regarding energy uplift credits for reactive services, units are not assured recovery of the entire offer including no load and startup costs as they are under the operating reserve credits rules. Units providing reactive services at the request of PJM are made whole through reactive service credits. But when the reactive services credits do not cover a unit's entire offer, the unit is made whole for the balance through balancing operating reserves. The result is a misallocation of the costs of providing reactive services. Reactive services credits are paid by real-time load in the control zone or zones where the service is provided while balancing operating reserve charges are paid by deviations from day-ahead or real-time load plus exports in the RTO, Eastern or Western Region depending on the allocation process rather than by zone.

The MMU recommends that reactive services credits be calculated consistent with the balancing operating reserve credit calculation. The MMU also recommends including real-time exports and real-time wheels in the allocation of the cost of providing reactive support to the 500 kV system or above, in addition to real-time load.[43]

Allocation Proposal

The elimination of the day-ahead operating reserve category and other MMU recommendations require enhancements to the current method of energy uplift allocation.

The current method allocates day-ahead operating reserve charges to day-ahead load, day-ahead exports and decrement bids. The elimination of the day-ahead operating reserve category would shift these costs to the balancing operating reserve category which would be paid by deviations or by real-time load plus real-time exports depending on the balancing operating reserve allocation rules.

The MMU recommends creating a new category for energy uplift payments to units scheduled in the Day-Ahead Energy Market (for reasons other than reactive or black start services) that do not recover their operating cost after operating in the Real-Time Energy Market. These payments would be allocated to all day-ahead transactions and resources. All these transaction types have an impact on the outcome of the day-ahead scheduling process, so allocating these costs to all day-ahead transactions ensures that all transactions that affect the way the Day-Ahead Energy Market clears are responsible for any energy uplift credits paid to the units scheduled in the Day-Ahead Energy Market. Energy uplift payments to units scheduled as must run in the Day-Ahead Energy Market (for reasons related to expected conditions in the real-time market not including reactive or black start services) should be allocated to real-time load, real-time exports and real-time wheels.

41 See PJM. "Item 12 - October 2012 MIC DAM Cost Allocation," PJM presentation to the Market Implementation Committee (October 12, 2012).

42 OATT Attachment K–Appendix § 3.2.3B (f).

43 See the Day-Ahead Reliability and Reactive Cost Allocation Final Report (December 13, 2013) for a complete description of the issues discussed in that group. <http://www.pjm.com/~/media/committees-groups/task-forces/emustf/20131220/20131220-item-02b-darrca-final-report.ashx>.

The MMU recommends allocating energy uplift payments to units not scheduled in the Day-Ahead Energy Market and committed in real time, but before the operating day, to the current deviation categories with the addition of up to congestion, wheels and units that clear the Day-Ahead Scheduling Reserve Market but do not perform.

The MMU recommends allocating energy uplift payments to units committed during the operating day to a new deviation category which would include physical transactions or resources (day-ahead minus real-time load, day-ahead minus real-time interchange transactions, generators and DR not following dispatch). This allocation would ensure that commitment changes that occur during the operating day and that result in energy uplift payments are paid by transactions or resources affecting the commitment of units during the operating day. For example, real-time load or interchange transactions that do not bid in the Day-Ahead Energy Market, generators and DR resources that do not follow dispatch would be allocated these costs. Any reliability commitment should be allocated to real-time load, real-time exports and real-time wheels independently of the timing of the commitment.

The MMU recommends changing the allocation of lost opportunity cost and canceled resources. LOC paid to units scheduled in the Day-Ahead Energy Market and not committed in real time should be allocated to deviations based on the proposed definition of deviations. LOC paid to units reduced for reliability in real time and payments to canceled resources should be allocated to real-time load, real-time exports and real-time wheels.

Table 4-40 shows the current allocation by energy uplift reason. For example, energy uplift payments to units scheduled in the Day-Ahead Energy Market are called day-ahead operating reserves, these costs are paid by day-ahead load, day-ahead exports and decrement bids. Any additional payment resulting from the real-time operation of these units are called balancing operating reserves, these costs are paid by either deviations or real-time load and real-time exports depending on the amount of intervals the units are economic.

Table 4-40 Current energy uplift allocation

Reason	Energy Uplift Category	Allocation Logic	Allocation
Units scheduled in the Day-Ahead Energy Market	Day-Ahead Operating Reserve	NA	Day-Ahead Load, Day-Ahead Exports and Decrement Bids
Units scheduled in the Day-Ahead Energy Market	Balancing Operating Reserve	LMP < Offer for at least four intervals	Real-Time Load and Real-Time Exports
		LMP > Offer for at least four intervals	Deviations
Units not scheduled in the Day-Ahead Energy Market and committed in real time	Balancing Operating Reserve	Committed before the operating day for reliability	Real-Time Load and Real-Time Exports
		Committed before the operating day to meet forecasted load and reserves	Deviations
		Committed during the operating day and LMP < Offer for at least four intervals	Real-Time Load and Real-Time Exports
		Committed during the operating day and LMP > Offer for at least four intervals	Deviations
Units scheduled in the Day-Ahead Energy Market not committed in real time	LOC Credit	NA	Deviations
Units reduced for reliability in real time	LOC Credit	NA	Deviations
Units canceled before coming online	Cancellation Credit	NA	Deviations

Table 4-41 shows the MMU allocation proposal by energy uplift reason. The proposal eliminates the day-ahead operating reserve category and creates a new category for any energy uplift payments to units scheduled in the Day-Ahead Energy Market and committed in real time. This new category would be allocated to day-ahead transactions and resources. The proposal also eliminates the need to determine the number of intervals that units are economic to determine if the energy uplift charge should be allocated to deviations or to real-time load and real-time exports. In the proposal, any commitment instruction before the operating day would be allocated based on the proposed definition of deviations; any commitment instruction during the operating day would be allocated to physical deviations.

Table 4-41 MMU energy uplift allocation proposal

Reason	Energy Uplift Category	Allocation Logic	Allocation
Units scheduled in the Day-Ahead Energy Market and committed in real time	Day-Ahead Segment Make Whole Credit	Scheduled by the day ahead model (not must run)	Day-Ahead Transactions and Day-Ahead Resources
		Scheduled as must run in the day ahead model	Real-Time Load, Real-Time Exports and Withdrawal Side of Real-Time Wheels
Units not scheduled in the Day-Ahead Energy Market and committed in real time	Real Time Segment Make Whole Credit	Committed before the operating day	Deviations
		Committed during the operating day	Physical Deviations
		Any commitment for reliability	Real-Time Load, Real-Time Exports and Withdrawal Side of Real-Time Wheels
Units scheduled in the Day-Ahead Energy Market not committed in real time	Day-Ahead LOC	NA	Deviations
Units reduced for reliability in real time	Real-Time LOC	NA	Real-Time Load, Real-Time Exports and Withdrawal Side of Real-Time Wheels
Units canceled before coming online	Cancellation Credit	NA	Real-Time Load, Real-Time Exports and Withdrawal Side of Real-Time Wheels

Capacity Market

Each organization serving PJM load must meet its capacity obligations through the PJM Capacity Market, where load serving entities (LSEs) must pay the locational capacity price for their zone. LSEs can also construct generation and offer it into the capacity market, enter into bilateral contracts, develop demand resources and energy efficiency (EE) resources and offer them into the capacity market, or construct transmission upgrades and offer them into the capacity market.

The Market Monitoring Unit (MMU) analyzed market structure, participant conduct and market performance in the PJM Capacity Market for 2018, including supply, demand, concentration ratios, pivotal suppliers, volumes, prices, outage rates and reliability.[1]

Table 5-1 The capacity market results were not competitive

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

- The aggregate market structure was evaluated as not competitive. For almost all auctions held from 2007 to the present, the PJM region failed the three pivotal supplier test (TPS), which is conducted at the time of the auction.[2] Structural market power is endemic to the capacity market.
- The local market structure was evaluated as not competitive. For almost every auction held, all LDAs have failed the TPS test, which is conducted at the time of the auction.[3]
- Participant behavior was evaluated as not competitive. Market power mitigation measures were applied when the Capacity Market Seller failed the market power test for the auction, the submitted sell offer exceeded the defined offer cap, and the submitted sell offer, absent mitigation, would increase the market clearing price. But the net CONE times B offer cap under the capacity performance design, in the absence of performance assessment hours, exceeds the competitive level and should be reevaluated for each BRA. In the 2021/2022 RPM Base Residual Auction, some participants' offers were above the competitive level. The MMU recognizes that these market participants followed the capacity market rules by offering at less than the stated offer cap of Net CONE times B. But Net CONE times B is not a competitive offer when the expected number of performance assessment intervals is zero or a very small number and the non-performance charge rate is defined as Net CONE/30. Under these circumstances, a competitive offer, under the logic defined in PJM's capacity performance filing, is net ACR. That is the way in which most market participants offered in this and prior capacity performance auctions.
- Market performance was evaluated as not competitive. Although structural market power exists in the Capacity Market, a competitive outcome can result from the application of market power mitigation rules. The outcome of the 2021/2022 RPM Base Residual Auction was not competitive as a result of participant behavior which was not competitive, specifically offers which exceeded the competitive level.
- Market design was evaluated as mixed because while there are many positive features of the Reliability Pricing Model (RPM) design and the capacity performance modifications to RPM, there are several features of the RPM design which still threaten competitive outcomes. These include the definition of DR which permits inferior products to substitute for capacity, the replacement capacity issue, the definition of unit offer parameters, the inclusion of imports which are not substitutes for internal capacity resources, and the definition of the default offer cap.

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

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

3 In the 2012/2013 RPM Base Residual Auction, six participants included in the incremental supply of EMAAC passed the TPS test. In the 2014/2015 RPM Base Residual Auction, seven participants in the incremental supply in MAAC passed the TPS test.

Overview

RPM Capacity Market

Market Design

The Reliability Pricing Model (RPM) Capacity Market is a forward-looking, annual, locational market, with a must offer requirement for Existing Generation Capacity Resources and mandatory participation by load, with performance incentives, that includes clear market power mitigation rules and that permits the direct participation of demand-side resources.[4]

Under RPM, capacity obligations are annual. Base Residual Auctions (BRA) are held for Delivery Years that are three years in the future. Effective with the 2012/2013 Delivery Year, First, Second and Third Incremental Auctions (IA) are held for each Delivery Year.[5] Prior to the 2012/2013 Delivery Year, the Second Incremental Auction was conducted if PJM determined that an unforced capacity resource shortage exceeded 100 MW of unforced capacity due to a load forecast increase. Effective January 31, 2010, First, Second, and Third Incremental Auctions are conducted 20, 10, and three months prior to the Delivery Year.[6] Also effective for the 2012/2013 Delivery Year, a Conditional Incremental Auction may be held if there is a need to procure additional capacity resulting from a delay in a planned large transmission upgrade that was modeled in the BRA for the relevant Delivery Year.[7]

The 2018/2019 RPM Third Incremental Auction, the 2021/2022 RPM Base Residual Auction, the 2019/2020 RPM Second Incremental Auction, and the 2020/2021 RPM First Incremental Auction were conducted in 2018.

On June 9, 2015, FERC accepted changes to the PJM capacity market rules proposed in PJM's Capacity Performance (CP) filing.[8] For a transition period during the 2018/2019 and 2019/2020 Delivery Years, PJM will procure two product types, Capacity Performance and Base Capacity. PJM also procured Capacity Performance resources in two transition auctions for the 2016/2017 and 2017/2018 Delivery Years. Effective with the 2020/2021 Delivery Year, PJM will procure a single capacity product, Capacity Performance. CP Resources are expected to be available and capable of providing energy and reserves when needed at any time during the Delivery Year.[9] Effective for the 2018/2019 through the 2019/2020 Delivery Years, a Base Capacity Demand Resource Constraint and a Base Capacity Resource Constraint are established for each modeled LDA. These maximum quantities are set for reliability purpose to limit the quantity procured of the less available products, including Base Capacity Generation Resources, Base Capacity Demand Resources, and Base Capacity Energy Efficiency Resources. The Capacity Performance (CP) Transition Incremental Auctions (IAs) were held as part of a five year transition to a single capacity product type in the 2020/2021 Delivery Year. Participation in the CP Transition IAs was voluntary. If a resource cleared a CP Transition IA and had a prior commitment for the relevant delivery year, the existing commitment was converted to a CP commitment, which is subject to the CP performance requirements and nonperformance charges. The Transition IAs were not designed to minimize the cost of purchasing Capacity Performance resources for the two delivery years and were not designed to maximize economic welfare for the two delivery years.

RPM prices are locational and may vary depending on transmission constraints.[10] Existing generation capable of qualifying as a capacity resource must be offered into RPM auctions, except for resources owned by entities that elect the fixed resource requirement (FRR) option. Participation by LSEs is mandatory, except for those entities that elect the FRR option. There is an administratively determined demand curve that defines scarcity pricing levels and that, with the supply curve derived from capacity offers, determines market prices in each BRA. RPM rules provide performance incentives for generation, including the requirement to submit generator outage data and the linking of capacity payments to the level of unforced capacity, and the performance incentives have been strengthened significantly under the Capacity Performance modifications to RPM. Under RPM there are explicit

4 The terms *PJM Region*, *RTO Region* and *RTO* are synonymous in this report and include all capacity within the PJM footprint.
5 See 126 FERC ¶ 61,275 at P 86 (2009).
6 See Letter Order, FERC Docket No. ER10-366-000 (January 22, 2010).
7 See 126 FERC ¶ 61,275 at P 88 (2009).
8 See 151 FERC ¶ 61,208 (2015).
9 See "PJM Manual 18: PJM Capacity Market," § 1.5 Transition to Capacity Performance, Rev. 41 (Jan. 1, 2019).
10 Transmission constraints are local capacity import capability limitations (low capacity emergency transfer limit (CETL) margin over capacity emergency transfer objective (CETO)) caused by transmission facility limitations, voltage limitations or stability limitations.

market power mitigation rules that define the must offer requirement, that define structural market power based on the marginal cost of capacity, that define offer caps, that define the minimum offer price, and that have flexible criteria for competitive offers by new entrants. Market power mitigation is effective only when these definitions are up to date and accurate. Demand resources and energy efficiency resources may be offered directly into RPM auctions and receive the clearing price without mitigation.

Market Structure

- **RPM Installed Capacity.** During 2018, RPM installed capacity increased 2,069.3 MW or 1.1 percent, from 183,882.4 MW on January 1 to 185,951.7 MW on December 31. Installed capacity includes net capacity imports and exports and can vary on a daily basis.
- **RPM Installed Capacity by Fuel Type.** Of the total installed capacity on December 31, 2018, 40.2 percent was gas; 32.7 percent was coal; 17.6 percent was nuclear; 4.8 percent was hydroelectric; 3.4 percent was oil; 0.6 percent was wind; 0.4 percent was solid waste; and 0.3 percent was solar.
- **Market Concentration.** In the 2018/2019 RPM Third Incremental Auction, 2019/2020 RPM Second Incremental Auction, 2021/2022 RPM Base Residual Auction, and the 2020/2021 RPM First Incremental Auction all participants in the total PJM market as well as the LDA RPM markets failed the three pivotal supplier (TPS) test.[11] Offer caps were applied to all sell offers for resources which were subject to mitigation when the Capacity Market Seller did not pass the test, the submitted sell offer exceeded the defined offer cap, and the submitted sell offer, absent mitigation, increased the market clearing price.[12] [13] [14]
- **Imports and Exports.** Of the 4,470.4 MW of imports in the 2021/2022 RPM Base Residual Auction, 4,051.8 MW cleared. Of the cleared imports, 1,909.9 MW (47.1 percent) were from MISO.
- **Demand-Side and Energy Efficiency Resources.** Capacity in the RPM load management programs was 10,798.7 MW for June 1, 2018, as a result of cleared capacity for demand resources and energy efficiency resources in RPM auctions for the 2018/2019 Delivery Year (13,731.7 MW) less replacement capacity (2,933.0 MW).

Market Conduct

- **2018/2019 RPM Base Residual Auction.** Of the 473 generation resources that submitted Base Capacity offers, the MMU calculated offer caps for 219 generation resources (46.3 percent), of which 166 (35.1 percent) were based on the technology specific default (proxy) ACR values and 53 (11.2 percent) were unit-specific offer caps. Of the 992 generation resources that submitted Capacity Performance offers, the MMU calculated unit specific offer caps for 35 generation resources (3.5 percent).
- **2018/2019 RPM First Incremental Auction.** Of the 80 generation resources that submitted Base Capacity offers, the MMU calculated offer caps for 30 generation resources (37.5 percent), of which 18 (22.5 percent) were based on the technology specific default (proxy) ACR values and 12 (15.0 percent) were unit-specific offer caps. Of the 293 generation resources that submitted Capacity Performance offers, the MMU calculated unit specific offer caps for nine generation resources (3.1 percent).
- **2018/2019 RPM Second Incremental Auction.** Of the 68 generation resources that submitted Base Capacity offers, the MMU calculated offer caps for 23 generation resources (33.8 percent), of which 12 (17.6 percent) were based on the technology specific default (proxy) ACR values and 11 (16.2 percent) were unit-specific offer caps. Of the 344 generation resources that submitted Capacity Performance offers, the MMU calculated unit specific offer caps for five generation resources (1.5 percent).
- **2018/2019 RPM Third Incremental Auction.** Of the 211 generation resources that submitted Base Capacity offers, the MMU calculated offer caps for five generation resources (2.4 percent), of which one

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

12 See OATT Attachment DD § 6.5.

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

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

(0.5 percent) was based on the technology specific default (proxy) ACR values and four (1.9 percent) were unit-specific offer caps. Of the 495 generation resources that submitted Capacity Performance offers, the MMU calculated unit specific offer caps for three generation resources (0.6 percent).

- **2019/2020 RPM Base Residual Auction.** Of the 505 generation resources that submitted Base Capacity offers, the MMU calculated offer caps for 212 generation resources (42.0 percent), of which 171 (33.9 percent) were based on the technology specific default (proxy) ACR values and 41 (8.1 percent) were unit-specific offer caps. Of the 1,003 generation resources that submitted Capacity Performance offers, the MMU calculated unit specific offer caps for 25 generation resources (2.5 percent).
- **2019/2020 RPM First Incremental Auction.** Of the 81 generation resources that submitted Base Capacity offers, the MMU calculated offer caps for 28 generation resources (34.6 percent), of which 17 (21.0 percent) were based on the technology specific default (proxy) ACR values and 11 (13.6 percent) were unit-specific offer caps. Of the 382 generation resources that submitted Capacity Performance offers, the MMU calculated unit specific offer caps for six generation resources (1.6 percent).
- **2019/2020 RPM Second Incremental Auction.** Of the 72 generation resources that submitted Base Capacity offers, the MMU calculated unit specific offer caps for eight generation resources (11.1 percent). Of the 409 generation resources that submitted Capacity Performance offers, the MMU calculated unit specific offer caps for six generation resources (1.5 percent).
- **2020/2021 RPM Base Residual Auction.** Of the 1,114 generation resources that submitted Capacity Performance offers, the MMU calculated unit specific offer caps for 14 generation resources (1.3 percent).
- **2020/2021 RPM First Incremental Auction.** Of the 397 generation resources that submitted Capacity Performance offers, the MMU calculated unit specific offer caps for eight generation resources (2.0 percent).
- **2021/2022 RPM Base Residual Auction.** Of the 1,132 generation resources that submitted Capacity Performance offers, the MMU calculated unit specific offer caps for eight generation resources (0.7 percent).

— The conduct of some participants was determined to be not competitive.

Market Performance

- The 2018/2019 RPM Third Incremental Auction, the 2021/2022 RPM Base Residual Auction, the 2019/2020 RPM Second Incremental Auction, and the 2020/2021 RPM First Incremental Auction were conducted in 2018. The weighted average capacity price for the 2018/2019 Delivery Year is $172.09, including all RPM auctions for the 2018/2019 Delivery Year held 2018. The weighted average capacity price for the 2019/2020 Delivery Year is $112.63, including all RPM auctions for the 2019/2020 Delivery Year held through 2018.
- For the 2018/2019 Delivery Year, RPM annual charges to load are $11.0 billion.
- In the 2021/2022 RPM Base Residual Auction, market performance was determined to be not competitive as a result of noncompetitive offers that affected market results.

Reliability Must Run Service

- Of the seven companies (23 units) that have provided RMR service, two companies (seven units) filed to be paid for RMR service under the deactivation avoidable cost rate (DACR), the formula rate. The other five companies (16 units) filed to be paid for RMR service under the cost of service recovery rate.

Generator Performance

- **Forced Outage Rates.** The average PJM EFORd for 2018 was 7.2 percent, an increase from 7.1 percent for 2017.[15]
- **Generator Performance Factors.** The PJM aggregate equivalent availability factor for 2018 was 83.2 percent, a decrease from 83.9 percent for 2017.

15 The generator performance analysis includes all PJM capacity resources for which there are data in the PJM generator availability data systems (GADS) database. This set of capacity resources may include generators in addition to those in the set of generators committed as capacity resources in RPM. Data was downloaded from the PJM GADS database on February 1, 2019. EFORd data presented in state of the market reports may be revised based on data submitted after the publication of the reports as generation owners may submit corrections at any time with permission from PJM GADS administrators.

- **Outages Deemed Outside Management Control (OMC).** In 2018, 1.2 percent of forced outages were classified as OMC outages.

Recommendations[16]

The MMU recognizes that PJM has implemented the Capacity Performance Construct to replace some of the existing core market rules and to address fundamental performance incentive issues. The MMU recognizes that the Capacity Performance Construct addresses many of the MMU's recommendations. The MMU's recommendations are based on the existing capacity market rules. The status is reported as adopted if the recommendation was included in FERC's order approving PJM's Capacity Performance filing.[17]

Definition of Capacity

- 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.[18] [19] (Priority: High. First reported 2013. Status: Not adopted.)
- The MMU recommends that DR providers be required to have a signed contract with specific customers for specific facilities for specific levels of DR at least six months prior to any capacity auction in which the DR is offered. (Priority: High. First reported 2016. Status: Not adopted.)

Market Design and Parameters

- The MMU recommends that the test for determining modeled Locational Deliverability Areas (LDAs) in RPM be redefined. A detailed reliability analysis of all at risk units should be included in the redefined model. (Priority: Medium. First reported 2013. Status: Not adopted.)
- The MMU recommends that the net revenue calculation used by PJM to calculate the net Cost of New Entry (CONE) VRR parameter reflect the actual flexibility of units in responding to price signals rather than using assumed fixed operating blocks that are not a result of actual unit limitations.[20] [21] The result of reflecting the actual flexibility is higher net revenues, which affect the parameters of the RPM demand curve and market outcomes. (Priority: High. First reported 2013. Status: Not adopted.)
- 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 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, there is no reason to have an add back mechanism. If EE remains on the supply side, the implementation of the EE add back mechanism should be modified to ensure that market clearing prices are not affected. (Priority: Medium. First reported 2016. Status: Not adopted.)
- The MMU recommends that PJM reduce the number of incremental auctions to a single incremental auction held three months prior to the start of the delivery year and reevaluate the triggers for holding conditional incremental auctions. (Priority: Medium. First reported 2013. Status: Not adopted.)
- The MMU recommends that PJM offer to sell back capacity in incremental auctions only at the BRA clearing price for the relevant delivery year. (Priority: Medium. First reported 2017. Status: Not adopted.)
- The MMU recommends changing the RPM solution method to explicitly incorporate the cost of make whole payments in the objective function. (Priority: Medium. First reported 2014. Status: Not adopted.)

16 The MMU has identified serious market design issues with RPM and the MMU has made specific recommendations to address those issues. These recommendations have been made in public reports. See Table 5-2.

17 151 FERC ¶ 61,208 (2015).

18 See also Comments of the Independent Market Monitor for PJM, Docket No. ER14-503-000 (December 20, 2013).

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

20 See PJM Interconnection, L.L.C., Docket No. ER12-513-000 (December 1, 2011) ("Triennial Review").

21 See the *2017 State of the Market Report for PJM*, Volume 2, Section 7: Net Revenue.

- The MMU recommends that PJM clear the capacity market based on nodal capacity resource locations and the characteristics of the transmission system consistent with the actual electrical facts of the grid. 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. (Priority: Medium. First reported 2017. Status: Not adopted.)

Offer Caps, Offer Floors, and Must Offer

- The MMU recommends use of the Sustainable Market Rule (SMR) in order to protect competition in the capacity market from nonmarket revenues.[22] (Priority: High. First reported 2016. Status: Not adopted.)
- The MMU recommends that, as part of the MOPR unit specific standard of review, all projects be required to use the same basic modeling assumptions. That is the only way to ensure that projects compete on the basis of actual costs rather than on the basis of modeling assumptions.[23] (Priority: High. First reported 2013. Status: Not adopted.)
- The MMU recommends that modifications to existing resources not be treated as new resources for purposes of market power related offer caps or MOPR offer floors. (Priority: Low. First reported 2012. Status: Not adopted.)
- The MMU recommends that the RPM market power mitigation rule be modified to apply offer caps in all cases when the three pivotal supplier test is failed and the sell offer is greater than the offer cap. This will ensure that market power does not result in an increase in make whole payments. (Priority: Medium. First reported 2017. Status: Not adopted.)
- 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 reserve margins, and other assumptions consistent with the annual IRM study. (Priority: High. First reported 2017. Status: Not adopted.)
- 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. (Priority: High. First reported 2017. Status: Not adopted.)
- 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. (Priority: Medium. First reported Q3, 2018. Status: Not adopted.)

Performance Incentive Requirements of RPM

- The MMU recommends that a unit which is not capable of supplying energy consistent with its day-ahead offer reflect an appropriate outage. (Priority: Medium. First reported 2009. Status: Not adopted.)
- The MMU recommends that retroactive replacement transactions associated with a failure to perform during a PAH not be allowed and that, more generally, retroactive replacement capacity transactions not be permitted. (Priority: Medium. First reported 2016. Status: Not adopted.)

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

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

- The 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. (Priority: Low. First reported 2013. Status: Not adopted.)

Capacity Imports and Exports

- 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. (Priority: High. First reported 2016. Status: Not adopted.)
- The MMU recommends that all costs incurred as a result of a pseudo tied unit be borne by the unit itself and included as appropriate in unit offers in the capacity market. (Priority: High. First reported 2016. Status: Not adopted.)
- 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. (Priority: Low. First reported 2010. Status: Partially adopted.)

Deactivations/Retirements

- The MMU recommends that the notification requirement for deactivations be extended from 90 days prior to the date of deactivation to 12 months prior to the date of deactivation and that PJM and the MMU be provided 60 days rather than 30 days to complete their reliability and market power analyses. (Priority: Low. First reported 2012. Status: Partially adopted.)
- The MMU recommends that 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. (Priority: Low. First reported 2010. Status: Not adopted.)
- 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. (Priority: Medium. First reported 2017. Status: Not adopted.)

Conclusion

The analysis of PJM Capacity Markets begins with market structure, which provides the framework for the actual behavior or conduct of market participants. The analysis examines participant behavior within that market structure. In a competitive market structure, market participants are constrained to behave competitively. The analysis examines market performance, measured by price and the relationship between price and marginal cost, that results from the interaction of market structure and participant behavior. Market power is and will remain endemic to the structure of the PJM Capacity Market. Nonetheless a competitive outcome can be assured by appropriate market power mitigation rules.

The MMU concludes that the 2021/2022 RPM Base Residual Auction results were not competitive as a result of offers above the competitive level by some market participants. The MMU recognizes that these market participants followed the capacity market rules by offering at less than the stated offer cap of Net CONE times B. But Net CONE times B is not a competitive offer when the expected number of performance assessment intervals is zero or a very small number and the non-performance charge rate is defined as Net CONE/30. Under these circumstances, a competitive offer, under the logic defined in PJM's capacity performance filing, is net ACR. That is the way in which most market participants offered in this and prior capacity performance auctions.

The FERC approved PJM tariff defines the offer cap as Net CONE times B, rather than including the full logic supporting the definition of the offer cap under the capacity performance paradigm. If the tariff had defined the offer cap consistent with PJM's filing in the capacity performance matter, the offer cap would have been net ACR rather than Net CONE times B.

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

The MMU found serious market structure issues, measured by the three pivotal supplier test results in the PJM Capacity Market in 2018. Explicit market power mitigation rules in the RPM construct only partially offset the underlying market structure issues in the PJM Capacity Market under RPM. In the 2021/2022 RPM Base Residual Auction, the default offer cap of net CONE times B exceeded the competitive offer for a number of resources. Some seasonal resources were paid additional make whole based on a failure of the market power rules to apply offer capping.

The MMU has identified serious market design issues with RPM and the MMU has made specific recommendations to address those issues.[24 25 26 27 28 29 30] In 2017 and 2018, the MMU prepared a number of RPM related reports and testimony, shown in Table 5-2. The capacity performance modifications to the RPM construct have significantly improved the capacity market and addressed many of the issues identified by the MMU. The MMU will continue to publish more detailed reports on the CP auctions which include more specific issues and suggestions for improvements.

The PJM markets have worked to provide incentives to entry and to retaining capacity. PJM had excess reserves of more than 9,000 MW on June 1, 2018, and will have excess reserves of more than 17,000 MW on June 1, 2019, based on current positions.[31] Capacity investments in PJM were financed by market sources. Of the 30,881.7 MW of additional capacity that cleared in RPM auctions for the 2007/2008 through 2017/2018 delivery years, 22,419.7 MW (72.6 percent) were based on market funding. Of the 13,553.8 MW of additional capacity that cleared in RPM auctions for the 2018/2019 through 2021/2022 delivery years, 11,752.4 MW (86.7 percent) are based on market funding. Those investments were made based on the assumption that markets would be allowed to work and that inefficient units would exit.

The issue of external subsidies emerged more fully in 2017 and 2018. The subsidies are not part of the PJM market design but nonetheless threaten the foundations of the PJM capacity market as well as the competitiveness of PJM markets overall.

The Ohio subsidy proceedings, the Illinois ZEC legislation to subsidize the Quad Cities nuclear power plant, the request in Pennsylvania to subsidize the Three Mile Island nuclear power plant, the New Jersey legislation to subsidize the Salem and Hope Creek nuclear power plants, the potential U.S. DOE proposal to subsidize coal and nuclear power plants, and the request by FirstEnergy to the U.S. DOE for subsidies consistent with the DOE Grid Resilience Proposal, all originate from the fact that competitive markets result in the exit of uneconomic and uncompetitive generating units. Regardless of the specific rationales offered by unit owners, the proposed solution for all such generating units has been to provide out of market subsidies in order to retain such units. The proposed solution in all cases ignores the opportunity cost of subsidizing uneconomic units, which is the displacement of new resources and technologies that would otherwise be economic. These subsidies are not accurately characterized as state subsidies. These subsidies were all requested by the owners of specific uneconomic generating units in order to improve the profitability of those specific units. These subsidies were not requested to accomplish broader social goals. Broader social goals can all be met with market-based mechanisms available to all market participants on a competitive basis and without discrimination.

24 See "Analysis of the 2017/2018 RPM Base Residual Auction," <http://www.monitoringanalytics.com/reports/Reports/2014/IMM_Analysis_of_the_2017_2018_RPM_Base_Residual_Auction_20141006.pdf> (October 6, 2014).

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

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

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

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

29 See "Analysis of Replacement Capacity for RPM Commitments: June 1, 2007 to June 1, 2016," <http://www.monitoringanalytics.com/reports/Reports/2016/IMM_Analysis_of_Replacement_Capacity_for_RPM_Commitments_06012007_to_06012016_20161227.pdf> (December 27, 2016).

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

31 The calculated reserve margin for June 1, 2019, does not account for cleared buy bids that have not been used in replacement capacity transactions.

Subsidies are contagious. Competition in the markets could be replaced by competition to receive subsidies. Similar threats to competitive markets are being discussed by unit owners in other states and the potentially precedential nature of these actions enhances the urgency of creating an effective rule to maintain competitive markets by modifying market rules to address these subsidies.

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

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

Subsidies to specific resources that are uneconomic as a result of competition are an effort to reverse market outcomes with no commitment to a regulatory model and no attempt to mitigate negative impacts on competition. The unit specific subsidy model is inconsistent with the PJM market design and inconsistent with the market paradigm and constitutes a significant threat to both.

The existing FRR approach remains an option for utilities with regulated revenues based on cost of service rates, including both privately and publicly owned (including public power entities and electric cooperatives) utilities. Such regulated utilities have had and continue to have the ability to opt out of the capacity market and provide their own capacity.

Given that states have increasingly aggressive renewable energy targets, a core goal of a competitive market design should be to ensure that the resources required to provide reliability receive appropriate competitive market incentives for entry and for ongoing investment and for exit when uneconomic. A significant level of renewable resources, operating with zero or near zero marginal costs, will result in very low energy prices. Since renewable resources are intermittent, the contribution of renewables to meeting reliability targets must be analyzed carefully to ensure that the capacity value is calculated correctly.

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

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

The expected impact of the SMR design on the offers and clearing of renewable resources and nuclear plants would be from zero to insignificant. The competitive offers of renewables, based on the net ACR of current technologies, are likely to clear in the capacity market. The competitive offers of nuclear plants, based on net ACR, are likely to clear in the capacity market.

Cost of service resources have the option of using the existing FRR rules, which would allow regulated utilities to opt out of the capacity market. The expected impact of the SMR design on the offers and clearing of regulated cost of service resources that remained in the capacity market would be from zero to insignificant. The competitive offers of these resources, based on net ACR, are likely to clear in the capacity market.

To the extent that there are shared broader goals related to PJM markets, they should also be addressed, but this can happen with a slightly longer lead time. If a shared goal is to reduce carbon output, a price on carbon is the market based solution. If a shared goal is increased renewables in addition to their carbon attributes, a common approach to RECs would be a market based solution. Fuel diversity has also been mentioned as an issue. Current fuel diversity is higher than ever in PJM. If there is an issue, the real issue is fuel security and not fuel diversity. Significant reliance on specific fuels, including nuclear, coal and gas means that markets are at risk from a significant disruption in any one fuel. If fuel security for gas is a concern, a number of issues should be considered including the reliability of the pipelines, the compatibility of the gas pipeline and the merchant generator business models, the degree to which electric generators have truly firm gas service and the need for a gas RTO to help ensure reliability.

As a result of the fact that demand side resources have contributed to price suppression in PJM capacity markets, the place of demand side in PJM should be reexamined. There are ways to ensure and enhance the vibrancy of demand side without negatively affecting markets for generation. There are other price formation issues in the capacity market that should also be examined and addressed.

Table 5-2 RPM related MMU reports: 2017 through 2018

Date	Name
January 11, 2017	Replacement Capacity http://www.monitoringanalytics.com/reports/Presentations/2017/IMM_MIC_Replacement_Capacity_Report_20170111.pdf
January 24, 2017	Summary of BRA Analysis Results: 2013/2014 - 2019/2020 http://www.monitoringanalytics.com/reports/Reports/2017/IMM_BRA_Scenario_Results_Summary_20170124.pdf
January 30, 2017	IMM Answer re Amended Calpine MOPR Complaint Docket No. EL16-49-000 http://www.monitoringanalytics.com/reports/Reports/2017/IMM_Answer_Docket_No_EL16-49_20170130.pdf
February 13, 2017	IMM Answer re Base Capacity Complaint Docket Nos. EL17-32 and EL17-36 http://www.monitoringanalytics.com/reports/Reports/2017/IMM_Answer_Docket_Nos_EL17-32_EL17-36_20170213.pdf
February 24, 2017	Generation Capacity Resources in PJM Region Subject to RPM Must Offer Obligation for 2017/2018, 2018/2019 and 2019/2020 Delivery Years http://www.monitoringanalytics.com/reports/Market_Messages/Messages/RPM_Must_Offer_Obligation_20170224.pdf
March 1, 2017	Incremental Auction Review http://www.monitoringanalytics.com/reports/Presentations/2017/IMM_IASTF_Incremental_Auction_Review_20170301.pdf
May 11, 2017	Generation Capacity Resources in PJM Region Subject to RPM Must Offer Obligation for 2018/2019, 2019/2020 and 2020/2021 Delivery Years http://www.monitoringanalytics.com/reports/Market_Messages/RPM_Material/RPM_Must_Offer_Obligation_20170509.pdf
June 27, 2017	MMU Incremental Auction Recommendation - Package B http://www.monitoringanalytics.com/reports/Presentations/2017/IMM_IASTF_MMU_Package_B_Summary_20170627.pdf
June 27, 2017	Replacement Capacity Issues http://www.monitoringanalytics.com/reports/Presentations/2017/IMM_IASTF_Replacement_Capacity_Issues_20170627.pdf
August 30, 2017	IMM Answer re IMM MOPR Exemption Complaint Docket No. EL17-82 http://www.monitoringanalytics.com/reports/Reports/2017/IMM_Answer_Docket_No_EL17-82_20170830.pdf
August 30, 2017	Incremental Auction Design Changes, Package B http://www.monitoringanalytics.com/reports/Presentations/2017/IMM_IASTF_Package_B_Executive_Summary_20170830.pdf
September 5, 2017	IMM Comments re PJM Deficiency Letter Compliance Docket No. ER17-775-002 http://www.monitoringanalytics.com/reports/Reports/2017/IMM_Comments_Docket_No_ER17-775-002_20170905.pdf
September 8, 2017	Generation Capacity Resources in PJM Region Subject to RPM Must Offer Obligation for 2018/2019, 2019/2020 and 2020/2021 Delivery Years http://www.monitoringanalytics.com/reports/Market_Messages/RPM_Material/RPM_Must_Offer_Obligation_20170509.pdf
September 11, 2017	IMM CCPPSTF Proposal http://www.monitoringanalytics.com/reports/Presentations/2017/IMM_CCPPSTF_Proposal_20170911.pdf
September 12, 2017	IMM Answer re Pleasants Transfer Docket No. EC17-88 http://www.monitoringanalytics.com/reports/Reports/2017/IMM_Answer_Docket_No_EC17-88_20170912.pdf
October 17, 2017	Revised IMM MOPR-Ex Proposal for CCPPSTF http://www.monitoringanalytics.com/reports/Presentations/2017/IMM_Letter_CCPPSTF_IM_%20Proposal_Summary_Revised_20171017.pdf
November 2, 2017	IMM MOPR-Ex Proposal for the CCPPSTF http://www.monitoringanalytics.com/reports/Presentations/2017/IMM_CCPPSTF_Proposal_Summary_Revised_20171103.pdf
November 12, 2017	IMM MOPR-Ex Proposal for the CCPPSTF http://www.monitoringanalytics.com/reports/Presentations/2017/IMM_CCPPSTF_Proposal_Summary_Revised_3_Redline_20171112.pdf
November 14, 2017	IMM Answer re MOPR Reforms Docket No. ER13-535 http://www.monitoringanalytics.com/reports/Reports/2017/IMM_Answer_Docket_No_ER13-535_20171114.pdf
November 17, 2017	Analysis of 2020/2021 RPM Base Residual Auction http://www.monitoringanalytics.com/reports/Reports/2017/IMM_Analysis_of_the_20202021_RPM_BRA_20171117.pdf
December 12, 2017	IMM MOPR-Ex RPS Status http://www.monitoringanalytics.com/reports/Presentations/2017/IMM_MRC_Special_Session_MOPR-Ex_RPS_Status_20171212.pdf
December 12, 2017	IMM MOPR-Ex Proposal Language - Revised http://www.monitoringanalytics.com/reports/Presentations/2017/IMM_MRC_Special_Session_MOPR_Ex_Proposal_Language_Revised_20171212.pdf
December 14, 2017	Analysis of Replacement Capacity for RPM Commitments: June 1, 2007 to June 1, 2017 http://www.monitoringanalytics.com/reports/Reports/2017/IMM_Report_on_Capacity_Replacement_Activity_4_20171214.pdf
December 21, 2017	MOPR-Ex Proposal Language Revised - 2 http://www.monitoringanalytics.com/reports/Presentations/2017/IMM_MOPR-Ex_Proposal_Language_Revised_2_2017121.pdf

Table 5-2 RPM related MMU reports: 2017 through 2018 (continued)

Date	Name
December 21, 2017	MOPR-Ex Proposal Language - Revised 3 http://www.monitoringanalytics.com/reports/Presentations/2017/IMM_MOPR-Ex_Proposal_Language_Revised_3_20171213.pdf
December 21, 2017	IMM MOPR-Ex RPS Status Revisions http://www.monitoringanalytics.com/reports/Presentations/2017/IMM_MRC_MOPR-Ex_RPS_Status_Revisions_20171214.pdf
December 21, 2017	MOPR-Ex Proposal http://www.monitoringanalytics.com/reports/Presentations/2017/IMM_MRC_MOPR-Ex_Proposal_20171221.pdf
December 22, 2017	IMM Parameter Limited Schedule Matrix (Annual) http://www.monitoringanalytics.com/reports/Market_Messages/Messages/IMM_Parameter_Limited_Schedule_Market_Notice_20171222.pdf
December 27, 2017	Generation Capacity Resources in PJM Region Subject to RPM Must Offer Obligation for 2018/2019, 2019/2020 and 2020/2021 Delivery Years http://www.monitoringanalytics.com/reports/Market_Messages/Messages/RPM_Must_Offer_Obligations_20171227.pdf
January 19, 2018	Analysis of Replacement Capacity for RPM Commitments http://www.monitoringanalytics.com/reports/Presentations/2018/IMM_IASTF_Analysis_of_Replacement_Capacity_for_RPM_Commitments_20180119.pdf
January 25, 2018	MOPR-Ex Main Motion http://www.monitoringanalytics.com/reports/Presentations/2018/IMM_MRC_MOPR-Ex_Main_Motion_20180125.pdf
January 25, 2018	MOPR-Ex Alternate Proposal http://www.monitoringanalytics.com/reports/Presentations/2018/IMM_MRC_MOPR-Ex_Alternate_Proposal_20180125.pdf
January 25, 2018	MOPR-Ex Memo http://www.monitoringanalytics.com/reports/Presentations/2018/IMM_MRC_MOPR-Ex_Memo_20180125.pdf
February 23, 2018	Generation Capacity Resources in PJM Region Subject to RPM Must Offer Obligation for 2018/2019, 2019/2020 and 2020/2021 Delivery Years http://www.monitoringanalytics.com/reports/Market_Messages/RPM_Material/IMM_Notice_RPM_Must_Offer_Obligations_20180223.pdf
March 9, 2018	Generation Additions and Retirements in the PJM Capacity Market: MW and Funding Sources http://www.monitoringanalytics.com/reports/Reports/2018/IMM_Generation_Additions_and_Retirements_in_the_PJM_Capacity_Market_20180309.pdf
April 11, 2018	IMM Comments re Base Capacity Complaint Docket Nos. EL17-32 and EL17-36 http://www.monitoringanalytics.com/reports/Reports/2018/IMM_Comments_Docket_No_EL17-32_EL17-36_20180411.pdf
May 9, 2018	Generation Capacity Resources in PJM Region Subject to RPM Must Offer Obligation for 2019/2020, 2020/2021 and 2021/2022 Delivery Years http://www.monitoringanalytics.com/reports/Market_Messages/Messages/IMM_Notice_RPM_Must_Offer_Obligations_20180509.pdf
June 1, 2018	IMM CONE CT Study Results http://www.monitoringanalytics.com/reports/Presentations/2018/IMM_MIC_Quadrennial_Review_Special_Session_CONE_CT_Study_Results_20180601.pdf
June 7, 2018	Generation Capacity Resources in PJM Region Subject to RPM Must Offer Obligation for 2019/2020, 2020/2021 and 2021/2022 Delivery Years http://www.monitoringanalytics.com/reports/Market_Messages/Messages/IMM_Notice_RPM_Must_Offer_Obligations_20180706.pdf
June 13, 2018	IMM Post Technical Conf. Comments re Base Capacity Complaint Docket No. EL17-31, -36 http://www.monitoringanalytics.com/Filings/2018/IMM_Post_Tech_Conf_Comments_Docket_No_EL17-32_-36_20180713.pdf
June 22, 2018	IMM CONE CT Study Results http://www.monitoringanalytics.com/reports/Presentations/2018/IMM_MIC_Quadrennial_Review_Special_Session_CONE_CT_Study_Results_20180601.pdf
August 24, 2018	Analysis of the 2021/2022 RPM Base Residual Auction - Revised http://www.monitoringanalytics.com/reports/Reports/2018/IMM_Analysis_of_the_20212022_RPM_BRA_Revised_20180824.pdf
August 24, 2018	Generation Capacity Resources in PJM Region Subject to RPM Must Offer Obligation for 2019/2020, 2020/2021 and 2021/2022 Delivery Years (PDF) http://www.monitoringanalytics.com/reports/Market_Messages/Messages/IMM_Notice_RPM_Must_Offer_Obligations_20180824.pdf
September 26, 2018	MOPR/FRR Sensitivity Analyses of the 2021/2022 RPM Base Residual Auction http://www.monitoringanalytics.com/reports/Reports/2018/IMM_MOPR_FRR_Sensitivity_Analyses_Report_20180926.pdf
October 2, 2018	IMM Brief re Capacity Market Investigation Docket Nos. EL16-49-000,ER18-1314-000,-001, EL18-178 http://www.monitoringanalytics.com/Filings/2018/IMM_Brief_Docket_No_EL16-49_EL18-178_ER18-1314_20181002.pdf
October 22, 2018	IMM Comments re NJ ZECs Docket No. EO18080899 http://www.monitoringanalytics.com/Filings/2018/IMM_Comments_Docket_No_EO18080899_20181022.pdf
October 23, 2018	IMM Notice of Withdrawal re Fairless MOPR Docket No. EL17-82 http://www.monitoringanalytics.com/Filings/2018/IMM_Notice_of_Withdrawal_Docket_No_EL17-82_20181023.pdf
October 31, 2018	IMM Summary of Position re Capacity Market Investigation Docket Nos. EL18-178, ER18-1314-000,-001, EL16-49 http://www.monitoringanalytics.com/Filings/2018/IMM_Summary_of_Position_Docket_No__EL18-178_ER18-1314_EL16-49.pdf
November 6, 2018	IMM Brief re Capacity Market Investigation Docket Nos. EL18-178, ER18-1314-000,-001, EL16-49 http://www.monitoringanalytics.com/Filings/2018/IMM_Reply_Brief_Docket_No_EL18-178_ER18-1314-000_001_EL16-49_20181106.pdf
November 19, 2018	IMM Protest re Quadrennial Review Docket No. ER19-105 http://www.monitoringanalytics.com/Filings/2018/IMM_Protest_Docket_No_ER19-105_20181119.pdf
November 19, 2018	IMM Protest re Maintenance Adders Docket No. ER19-210 http://www.monitoringanalytics.com/Filings/2018/IMM_Protest_Docket_No_ER19-210_20181119.pdf
December 21, 2018	IMM Answer and Motion for Leave to Answer re VOM Complaint and Maintenance Adder Docket No. EL19-8, ER19-210 http://www.monitoringanalytics.com/Filings/2018/IMM_Answer_Docket_Nos_EL19-8_ER19-210_20181221.pdf
December 31, 2018	Generation Capacity Resources in PJM Region Subject to RPM Must Offer Obligation for 2019/2020, 2020/2021 and 2021/2022 Delivery Years http://www.monitoringanalytics.com/reports/Market_Messages/Messages/RPM_Must_Offer_Obligation_20181231.pdf

Installed Capacity

On January 1, 2018, RPM installed capacity was 183,882.4 MW (Table 5-3).[32] Over the next twelve months, new generation, unit deactivations, facility reratings, plus import and export shifts resulted in RPM installed capacity of 185,951.7 MW on December 31, 2018, an increase of 2,069.3 MW or 1.1 percent from the January 1 level.[33] [34] The 2,069.3 MW increase was the result of new or reactivated generation (8,381.6 MW), a decrease in exports (224.9 MW), and uprates (526.3 MW), offset by deactivations (5,596.9 MW), a decrease in imports (1,323.3 MW), and derates (143.3 MW).

At the beginning of the new delivery year on June 1, 2018, RPM installed capacity was 183,386.2 MW, a decrease of 1,658.3 MW or 0.9 percent from the May 31, 2018 level.

Figure 5-1 shows the share of installed capacity by fuel source for the first day of each delivery year, from June 1, 2007, to June 1, 2018, as well as the expected installed capacity for the next three delivery years, based on the results of all auctions held through December 31, 2018.[35] On June 1, 2007, coal comprised 40.7 percent of the installed capacity, reached a maximum of 42.9 percent in 2012, decreased to 33.3 percent on June 1, 2018 and is projected to decrease to 28.2 percent by June 1, 2021. The share of gas increased from 29.1 percent in 2007 to 38.9 percent in 2018 and is projected to increase to 50.3 percent in 2021.

Table 5-3 Installed capacity (By fuel source): January 1, May 31, June 1, and December 31, 2018

	01-Jan-18		31-May-18		01-Jun-18		31-Dec-18	
	MW	Percent	MW	Percent	MW	Percent	MW	Percent
Coal	65,144.0	35.4%	64,992.8	35.1%	61,033.1	33.3%	60,763.4	32.7%
Gas	67,811.4	36.9%	69,256.9	37.4%	71,241.8	38.8%	74,716.8	40.2%
Hydroelectric	8,856.2	4.8%	8,819.0	4.8%	8,888.2	4.8%	8,888.2	4.8%
Nuclear	33,163.5	18.0%	33,242.2	18.0%	33,292.2	18.2%	32,684.5	17.6%
Oil	6,587.2	3.6%	6,429.4	3.5%	6,388.2	3.5%	6,388.2	3.4%
Solar	374.0	0.2%	374.0	0.2%	589.1	0.3%	640.0	0.3%
Solid waste	809.4	0.4%	786.4	0.4%	795.3	0.4%	712.3	0.4%
Wind	1,136.7	0.6%	1,143.8	0.6%	1,158.3	0.6%	1,158.3	0.6%
Total	183,882.4	100.0%	185,044.5	100.0%	183,386.2	100.0%	185,951.7	100.0%

32 Percent values shown in Table 5-3 are based on unrounded, underlying data and may differ from calculations based on the rounded values in the tables.

33 Unless otherwise specified, the capacity described in this section is the summer installed capacity rating of all PJM generation capacity resources, as entered into the eRPM system, regardless of whether the capacity cleared in the RPM auctions.

34 Wind resources accounted for 1,158.3 MW, and solar resources accounted for 640.0 MW of installed capacity in PJM on December 31, 2018. PJM administratively reduces the capabilities of all wind generators to 14.7 percent for wind farms in mountainous terrain and 17.6 percent for wind farms in open terrain, and solar generators to 42.0 percent for ground mounted fixed panel, 60.0 percent for ground mounted tracking panel, and 38.0 percent for other than ground mounted solar arrays, of nameplate capacity when determining the installed capacity because wind and solar resources cannot be assumed to be available on peak and cannot respond to dispatch requests. As data become available, unforced capability of wind and solar resources will be calculated using actual data. There are additional wind and solar resources not reflected in total capacity because they are energy only resources and do not participate in the PJM Capacity Market. See "PJM Manual 21: Rules and Procedures for Determination of Generating Capability," § Appendix B: Calculating Capacity Values for Wind and Solar Capacity Resources, Rev. 12 (Jan. 1, 2017).

35 Due to EFORd values not being finalized for future delivery years, the projected installed capacity is based on cleared unforced capacity (UCAP) MW using the EFORd submitted with the offer.

Figure 5-1 Percent of installed capacity (By fuel source): June 1, 2007 through June 1, 2021

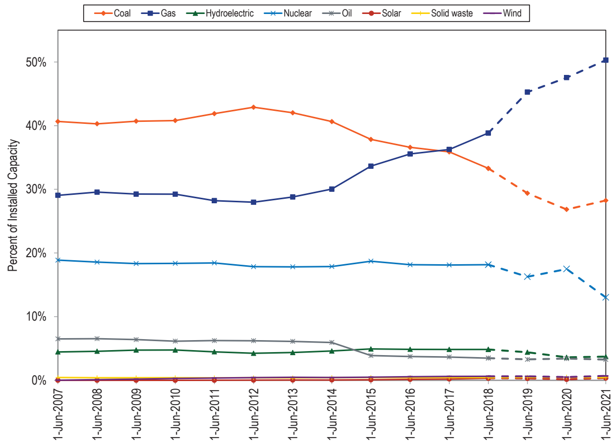


Table 5-4 shows the RPM installed capacity on January 1, 2018, through December 31, 2018, for the top five generation capacity resource owners, excluding FRR committed MW.

Table 5-4 Installed capacity by parent company: January 1, May 31, June 1, and December 31, 2018

	01-Jan-18			31-May-18			01-Jun-18			30-Sep-18			31-Dec-18		
Parent Company	ICAP (MW)	Percent of Total ICAP	Rank	ICAP (MW)	Percent of Total ICAP	Rank	ICAP (MW)	Percent of Total ICAP	Rank	ICAP (MW)	Percent of Total ICAP	Rank	ICAP (MW)	Percent of Total ICAP	Rank
Exelon Corporation	23,426.0	13.9%	1	23,423.1	13.8%	1	23,426.8	13.9%	1	22,819.1	13.4%	1	22,819.1	13.3%	1
Dominion Resources, Inc.	21,098.5	12.5%	2	20,467.3	12.0%	2	20,610.8	12.2%	2	20,527.8	12.1%	2	19,851.9	11.6%	2
FirstEnergy Corp.	15,840.6	9.4%	3	14,959.5	8.8%	4	14,943.3	8.9%	3	14,651.9	8.6%	3	14,644.0	8.5%	3
NRG Energy, Inc.	15,756.5	9.3%	4	15,745.0	9.3%	3	13,937.3	8.3%	4	13,810.5	8.1%	4	5,116.5	3.0%	10
Dynegy Inc.	12,307.4	7.3%	5												
Talen Energy Corporation	11,527.7	6.8%	6	11,121.2	6.5%	6	10,959.3	6.5%	6	10,959.3	6.4%	6	10,959.3	6.4%	5
Vistra Energy Corp.				13,388.2	7.9%	5	12,115.0	7.2%	5	12,133.3	7.1%	5	12,082.3	7.0%	4

Table 5-5 Installed capacity by funding type: January 1, May 31, June 1, and December 31, 2018

	01-Jan-18		31-May-18		01-Jun-18		31-Dec-18	
Funding Type	ICAP (MW)	Percent of Total ICAP	ICAP (MW)	Percent of Total ICAP	ICAP (MW)	Percent of Total ICAP	ICAP (MW)	Percent of Total ICAP
Market	151,193.8	82.2%	152,037.2	82.2%	150,108.7	81.9%	153,668.5	82.6%
Nonmarket	32,688.6	17.8%	33,007.3	17.8%	33,277.5	18.1%	32,283.2	17.4%
Total	183,882.4	100.0%	185,044.5	100.0%	183,386.2	100.0%	185,951.7	100.0%

The sources of funding for generation owners can be categorized as one of two types: market and nonmarket. Market funding is from private investors bearing the investment risk without guarantees or support from any public sources, subsidies or guaranteed payment by ratepayers. Providers of market funding rely entirely on market revenues. Nonmarket funding is from guaranteed revenues, including cost of service rates for a regulated utility and subsidies. Table 5-5 shows the RPM installed capacity on January 1, 2018, to December 31, 2018, by funding type.

Fuel Diversity

Figure 5-2 shows the fuel diversity index (FDI_c) for RPM installed capacity.[36] The FDI_c is defined as $1-\sum_{i=1}^{N} s_i^2$, where s_i is the percent share of fuel type i. The minimum possible value for the FDI_c is zero, corresponding to all capacity from a single fuel type. The maximum possible value for the FDI_c is achieved when each fuel type has an equal share of capacity. For a capacity mix of eight fuel types, the maximum achievable index is 0.875. The fuel type categories used in the calculation of the FDI_c are the eight fuel sources in Table 5-3. The FDI_c is stable and does not exhibit any long-term trends. The only significant deviation occurred with the expansion of the PJM footprint. On April 1, 2002, PJM expanded with the addition of Allegheny Power System, which added about 12,000 MW of generation.[37] The reduction in the FDI_c resulted from an increase in coal capacity resources. A similar but more significant reduction occurred in 2004

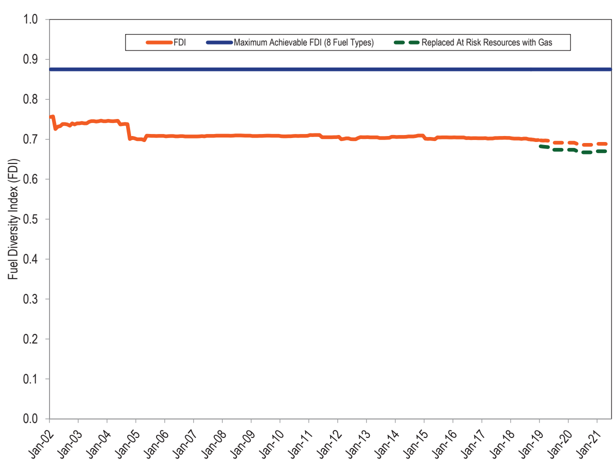
36 Monitoring Analytics developed the FDI to provide an objective metric of fuel diversity. The FDI metric is similar to the HHI used to measure market concentration. The FDI is calculated separately for energy output and for installed capacity.

37 On April 1, 2002, the PJM Region expanded with the addition of Allegheny Power System under a set of agreements known as "PJM-West." See page 4 in the *2002 State of the Market Report for PJM* for additional details.

with the expansion into the ComEd, AEP, and Dayton Power & Light control zones.[38] The average FDI_c for 2018 decreased 0.3 percent from 2017. Figure 5-2 also includes the expected FDI_c through June 2021 based on cleared RPM auctions. The expected FDI_c is indicated in Figure 5-2 by the dashed orange line.

The FDI_c was used to measure the impact of potential retirements of resources that the MMU has identified as being at risk of retirement. There were 18 capacity resources with installed capacity totaling 14,954 MW identified as being at risk of retirement. The dashed green line in Figure 5-2 shows the FDI_c calculated assuming that the capacity from these 18 resources that has cleared in a RPM auction is replaced by gas generation. The FDI_c under these assumptions would decrease by 0.018 (2.6 percent) on average from the expected FDI_c for the period January 1, 2019, through June 1, 2021.

Figure 5-2 Fuel Diversity Index for installed capacity: January 1, 2002 through June 1, 2021



RPM Capacity Market

The RPM Capacity Market, implemented June 1, 2007, is a forward-looking, annual, locational market, with a must-offer requirement for Existing Generation Capacity Resources and mandatory participation by load, with performance incentives, that includes clear market power mitigation rules and that permits the direct participation of demand-side resources.

Annual base auctions are held in May for delivery years that are three years in the future. Effective January 31, 2010, First, Second, and Third Incremental Auctions are conducted 20, 10, and three months prior to the delivery year.[39] In 2018, the 2018/2019 RPM Third Incremental Auction, the 2021/2022 RPM Base Residual Auction, the 2019/2020 RPM Second Incremental Auction, and the 2020/2021 RPM First Incremental Auction were conducted.

Market Structure

Supply

Table 5-6 shows generation capacity changes since the implementation of the Reliability Pricing Model through the 2017/2018 Delivery Year. The 19,726.8 MW increase was the result of new generation capacity resources (23,479.1 MW), reactivated generation capacity resources (971.0 MW), uprates (6,431.6 MW), integration of external zones (18,109.0 MW), a net increase in capacity imports (3,545.5 MW), a net decrease in capacity exports (2,519.2 MW), offset by deactivations (31,959.6 MW) and derates (3,369.0 MW).

Table 5-7 shows the calculated RPM reserve margin and reserve in excess of the defined installed reserve margin (IRM) for June 1, 2016, through June 1, 2021, and accounts for cleared capacity, replacement capacity, and deficiency MW for all auctions held and the final peak load forecast for the given delivery year. The completion of the replacement process using cleared buy bids from RPM incremental auctions includes two transactions. The first step is for the entity to submit and clear a buy bid in an RPM incremental auction. The next step is for the entity to complete a separate replacement transaction using the cleared buy bid capacity. The calculated reserve margins for June 1, 2019, and June 1, 2020, do not account for cleared buy bids that have not been used in replacement capacity transactions. Without an approved early replacement transaction requested for defined physical reasons, replacement capacity transactions can be completed only after the EFORds for the delivery year are finalized, on November 30 in the year prior to the delivery year, but before the start of the delivery day.

38 See the *2018 State of the Market Report for PJM*, Volume 2, Appendix A, "PJM Geography" for an explanation of the expansion of the PJM footprint. The integration of the ComEd Control Area occurred in May 2004 and the integration of the AEP and Dayton control zones occurred in October 2004.

39 See *PJM Interconnection, L.L.C.*, Letter Order in Docket No. ER10-366-000 (January 22, 2010).

Future Changes in Generation Capacity[40]

As shown in Table 5-6, for the period from the introduction of the RPM capacity market design in the 2007/2008 Delivery Year through the 2017/2018 Delivery Year, internal installed capacity decreased by 4,446.9 MW after accounting for new capacity resources, reactivations, and uprates (30,881.7 MW) and capacity deactivations and derates (35,328.6 MW).

For the current and future delivery years (2018/2019 through 2021/2022), new generation capacity is defined as capacity that cleared an RPM auction for the first time in the specified DY. Looking ahead, based on expected completion rates of cleared new generation capacity (10,654.1 MW) and pending deactivations (10,950.2 MW), PJM capacity is expected to decrease by 296.1 MW for the 2018/2019 through 2021/2022 Delivery Years.

Table 5-6 Generation capacity changes: 2007/2008 to 2018/2019

	ICAP (MW)									
	Total at June 1	New	Reactivations	Uprates	Integration	Net Change in Capacity Imports	Net Change in Capacity Exports	Deactivations	Derates	Net Change
2007/2008	163,659.4	372.8	156.8	1,238.1	0.0	(96.7)	143.9	389.5	617.8	519.8
2008/2009	164,179.2	812.9	6.3	1,108.9	0.0	871.1	(1,702.9)	615.0	612.4	3,274.7
2009/2010	167,453.9	188.1	13.0	370.4	0.0	68.6	735.9	472.4	171.2	(739.4)
2010/2011	166,714.5	1,751.2	16.0	587.3	11,821.6	187.2	(427.0)	1,439.2	286.9	13,064.2
2011/2012	179,778.7	3,095.0	138.0	553.8	3,607.4	262.7	(1,374.5)	2,758.5	313.0	5,959.9
2012/2013	185,738.6	266.4	79.0	364.5	2,680.0	841.8	(17.3)	4,152.1	267.6	(170.7)
2013/2014	185,567.9	264.7	20.9	397.9	0.0	2,217.2	21.6	4,027.7	421.9	(1,570.5)
2014/2015	183,997.4	3,036.0	0.0	480.4	0.0	859.1	73.3	11,442.9	221.0	(7,361.7)
2015/2016	176,635.7	5,497.8	0.0	409.0	0.0	787.6	285.1	863.4	156.4	5,389.5
2016/2017	182,025.2	2,537.8	537.0	589.8	0.0	(1,011.1)	(36.4)	1,447.3	167.8	1,074.8
2017/2018	183,100.0	5,656.4	4.0	331.5	0.0	(1,442.0)	(220.9)	4,351.6	133.0	286.2
2018/2019	183,386.2									
Total		23,479.1	971.0	6,431.6	18,109.0	3,545.5	(2,519.2)	31,959.6	3,369.0	19,726.8

Sources of Funding[41]

Developers use a variety of sources to fund their projects, including Power Purchase Agreements (PPA), cost of service rates, and private funds (from internal sources or private lenders and investors). PPAs can be used for a variety of purposes and the use of a PPA does not imply a specific source of funding.

New generation capacity from the 2007/2008 DY through the 2017/2018 DY totaled 23,479.1 MW (76.0 percent of all additions), with 16,450.0 MW from market funding and 7,029.1 MW from nonmarket funding. Reactivated generation capacity from the 2007/2008 DY through the 2017/2018 DY totaled 971.0 MW (3.1 percent of all additions), with 896.0 MW from market funding and 75.0 MW from nonmarket funding. Uprates to existing generation capacity from the 2007/2008 DY through the 2017/2018 DY totaled 6,431.6 MW (20.8 percent of all additions), with 5,073.7 MW from market funding and 1,357.9 MW from nonmarket funding. In summary, of the 30,881.7 MW of additional capacity from new, reactivated, and uprated generation that cleared in RPM auctions for the 2007/2008 through 2017/2018 delivery years, 22,419.7 MW (72.6 percent) were based on market funding.

Of the 8,159.3 MW of the additional generation capacity (new resources, reactivated resources, and uprates) that cleared in RPM auctions for the 2018/2019 through 2021/2022 delivery years, that are not yet in service, 6,536.3 MW have market funding and 1,623.0 MW have nonmarket funding. Applying the historical completion rates, 4,045.8 MW, or 61.9 percent, of the market funded projects are expected to go into service. Similarly, 1,163.2 MW, or 71.7 percent, of nonmarket funded projects are expected to go into service. Together, 5,209.1 MW, or 63.8 percent, of new generation capacity that cleared MW in RPM and are not yet in service are expected to go into service through the 2021/2022 Delivery Year.

Of the 5,394.5 MW of the additional generation capacity that cleared in RPM auctions for the 2018/2019

40 For more details on future changes in generation capacity, see "Generation Additions and Retirements in the PJM Capacity Market: MW and Funding Sources for Delivery Years 2007/2008 through 2020/2021," <http://www.monitoringanalytics.com/reports/Reports/2018/IMM_Generation_Additions_and_Retirements_in_the_PJM_Capacity_Market_20180309.pdf> (March 9, 2018).

41 For more details on sources of funding for generation capacity, see "Generation Additions and Retirements in the PJM Capacity Market: MW and Funding Sources for Delivery Years 2007/2008 through 2020/2021," <http://www.monitoringanalytics.com/reports/Reports/2018/IMM_Generation_Additions_and_Retirements_in_the_PJM_Capacity_Market_20180309.pdf> (March 9, 2018).

through 2021/2022 delivery years and are already in service, 5,216.1 MW (96.7 percent) are based on market funding. In summary, 11,752.4 MW (86.7 percent) of the additional generation capacity (5,216.1 MW in service and 6,536.3 MW not yet in service) that cleared in RPM auctions for the 2018/2019 through 2021/2022 delivery years are based on market funding. Capacity additions based on nonmarket funding are 1,801.4 MW (13.3 percent) of proposed generation that cleared at least one RPM auction for the 2018/2019 through 2021/2022 delivery years.

Table 5-7 RPM reserve margin: June 1, 2016 to June 1, 2021[42] [43]

	Generation and DR RPM Committed Less Deficiency UCAP (MW)	Forecast Peak Load	FRR Peak Load	PRD	RPM Peak Load	IRM	Pool Wide Average EFORd	Generation and DR RPM Committed Less Deficiency ICAP (MW)	Reserve Margin	Reserve Margin in Excess of IRM		Projected Replacement Capacity using Cleared Buy Bids UCAP (MW)	Projected Reserve Margin
										Percent	ICAP (MW)		
01-Jun-16	160,883.3	152,356.6	12,511.6	0.0	139,845.0	16.4%	5.91%	170,988.7	22.3%	5.9%	8,209.2	0.0	22.3%
01-Jun-17	163,872.0	153,230.1	12,837.5	0.0	140,392.6	16.6%	5.94%	174,220.7	24.1%	7.5%	10,522.9	0.0	24.1%
01-Jun-18	161,242.6	152,407.9	12,732.9	0.0	139,675.0	16.1%	6.07%	171,662.5	22.9%	6.8%	9,499.8	0.0	22.9%
01-Jun-19	167,892.2	151,643.5	12,284.2	0.0	139,359.3	16.0%	6.08%	178,760.9	28.3%	12.3%	17,104.1	3,988.8	25.2%
01-Jun-20	165,943.4	152,245.4	12,065.2	558.0	139,622.2	15.9%	5.97%	176,479.2	26.4%	10.5%	14,657.1	3,446.6	23.8%
01-Jun-21	160,795.3	152,647.4	12,107.1	510.0	140,030.3	15.8%	5.89%	170,858.9	22.0%	6.2%	8,703.8	0.0	22.0%

Demand

The MMU analyzed market sectors in the PJM Capacity Market to determine how they met their load obligations. The PJM Capacity Market was divided into the following sectors:

- **PJM EDC.** EDCs with a franchise service territory within the PJM footprint. This sector includes traditional utilities, electric cooperatives, municipalities and power agencies.
- **PJM EDC Generating Affiliate.** Affiliate companies of PJM EDCs that own generating resources.
- **PJM EDC Marketing Affiliate.** Affiliate companies of PJM EDCs that sell power and have load obligations in PJM, but do not own generating resources.
- **Non-PJM EDC.** EDCs with franchise service territories outside the PJM footprint.
- **Non-PJM EDC Generating Affiliate.** Affiliate companies of non-PJM EDCs that own generating resources.
- **Non-PJM EDC Marketing Affiliate.** Affiliate companies of non-PJM EDCs that sell power and have load obligations in PJM, but do not own generating resources.
- **Non-EDC Generating Affiliate.** Affiliate companies of non-EDCs that own generating resources.
- **Non-EDC Marketing Affiliate.** Affiliate companies of non-EDCs that sell power and have load obligations in PJM, but do not own generating resources.

On June 1, 2018 PJM EDCs and their affiliates maintained a large market share of load obligations under RPM, together totaling 59.8 percent (Table 5-8), down from 63.6 percent on June 1, 2017. The combined market share of LSEs not affiliated with any EDC and of non-PJM EDC affiliates was 40.2 percent, up from 36.4 percent on June 1, 2017. The share of capacity market load obligation fulfilled by PJM EDCs and their affiliates, and LSEs not affiliated with any EDC and non-PJM EDC affiliates from June 1, 2007 to June 1, 2018 is shown in Figure 5-3. PJM EDCs' and their affiliates' share of load obligation has decreased from 77.5 percent on June 1, 2007, to 59.8 percent on June 1, 2018. The share of load obligation held by LSEs not affiliated with any EDC and non-PJM EDC affiliates increased from 22.5 percent on June 1, 2007, to 40.2 percent on June 1, 2018. Prior to the 2012/2013 Delivery Year, obligation was defined as cleared and make whole MW in the Base Residual Auction and the Second Incremental Auction plus ILR forecast obligations. Effective with the 2012/2013 Delivery Year, obligation is defined as the sum of the unforced capacity obligations satisfied through all RPM auctions for the delivery year.

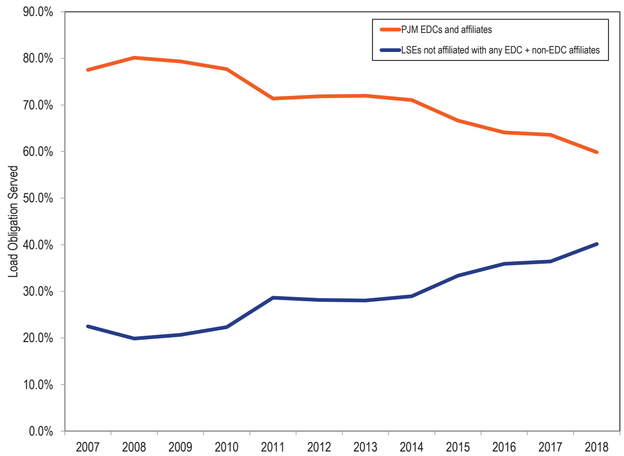
42 The calculated reserve margins in this table do not include EE on the supply side or the EE add back on the demand side. The EE excluded from the supply side for this calculation includes annual EE and summer EE. This is how PJM calculates the reserve margin.

43 These reserve margin calculations do not consider Fixed Resource Requirement (FRR) load.

Table 5-8 Capacity market load obligation served: June 1, 2018

	Obligation (MW)							
	PJM EDCs	PJM EDC Generating Affiliates	PJM EDC Marketing Affiliates	Non-PJM EDC Generating Affiliates	Non-PJM EDC Marketing Affiliates	Non-EDC Generating Affiliates	Non-EDC Marketing Affiliates	Total
Obligation	50,211.2	32,092.5	24,393.1	6,719.4	12,183.7	37,165.1	15,549.5	178,314.4
Percent of total obligation	28.2%	18.0%	13.7%	3.8%	6.8%	20.8%	8.7%	100.0%

Figure 5-3 Capacity market load obligation served: June 1, 2007 through June 1, 2018



Capacity Transfer Rights (CTRs)

Capacity Transfer Rights (CTRs) are used to return capacity market congestion revenues to load. Load pays for the transmission system through firm transmission charges and pays for congestion. Capacity market congestion revenues are the difference between the total dollars paid by load for capacity and the total dollars received by capacity market sellers. The MW of CTRs available for allocation to LSEs in an LDA is equal to the Unforced Capacity imported into the LDA, based on the results of the Base Residual Auction and Incremental Auctions, less any MW of CETL paid for directly by market participants in the form of Qualifying Transmission Upgrades (QTUs) cleared in an RPM Auction and Incremental Capacity Transfer Rights (ICTRs). There are two types of ICTRs, those allocated to a New Service Customer obligated to fund a transmission facility or upgrade and those associated with Incremental Rights-Eligible Required Transmission Enhancements.

For LDAs in which the RPM auctions for a delivery year resulted in a positive average weighted Locational Price Adder, an LSE with CTRs corresponding to the LDA is entitled to a payment or charge equal to the Locational Price Adder multiplied by the MW of the LSEs' CTRs.

In the 2021/2022 RPM Base Residual Auction, EMAAC had 4,352.6 MW of CTRs with a total value of $40,877,295, PSEG had 4,990.5 MW of CTRs with a total value of $70,238,159, ATSI had 6,402.8 MW of CTRs with a total value of $73,219,252, ComEd had 1,527.9 MW of CTRs with a total value of $30,978,820, and BGE had 5,125.6 MW of CTRs with a total value of $112,812,971.

EMAAC had 40.0 MW of customer funded ICTRs with a total value of $375,658, PSEG had 41.0 MW of customer funded ICTRs with a total value of $577,050, BGE had 65.7 MW of customer funded ICTRs with a total value of $6,734,907, and ComEd had 1,097.0 MW of customer funded ICTRs with a total value of $22,242,498.

EMAAC had 948.0 MW of ICTRs due to Incremental Rights-Eligible Required Transmission Enhancements with a value of $8,903,095. PSEG had 499.4 MW of ICTRs due to Incremental Rights-Eligible Required Transmission Enhancements with a value of $7,605,806. BGE had 306.0 MW of ICTRs due to Incremental Rights-Eligible Required Transmission Enhancements with a value of $8,180,931.

Market Concentration

Auction Market Structure

As shown in Table 5-9, in the 2018/2019 RPM Third Incremental Auction, the 2019/2020 RPM Second Incremental Auction, the 2021/2022 RPM Base Residual Auction, and the 2020/2021 RPM First Incremental Auction all participants in the total PJM market as well as the LDA RPM markets failed the three pivotal supplier (TPS).[44] Offer caps were applied to all sell offers for resources which were subject to mitigation when the capacity market seller did not pass the test, the submitted sell offer exceeded the defined offer cap, and

44 The market definition used for the TPS test includes all offers with costs less than or equal to 1.50 times the clearing price. See *MMU Technical Reference for PJM Markets*, at "Three Pivotal Supplier Test" for additional discussion.

the submitted sell offer, absent mitigation, increased the market clearing price.[45 46 47]

In applying the market structure test, the relevant supply for the RTO market includes all supply offered at less than or equal to 150 percent of the RTO cost-based clearing price. The relevant supply for the constrained LDA markets includes the incremental supply inside the constrained LDAs which was offered at a price higher than the unconstrained clearing price for the parent LDA market and less than or equal to 150 percent of the cost-based clearing price for the constrained LDA. The relevant demand consists of the MW needed inside the LDA to relieve the constraint.

Table 5-9 presents the results of the TPS test. A generation owner or owners are pivotal if the capacity of the owners' generation facilities is needed to meet the demand for capacity. The results of the TPS are measured by the residual supply index (RSIx). The RSIx is a general measure that can be used with any number of pivotal suppliers. The subscript denotes the number of pivotal suppliers included in the test. If the RSIx is less than or equal to 1.0, the supply owned by the specific generation owner, or owners, is needed to meet market demand and the generation owners are pivotal suppliers with a significant ability to influence market prices. If the RSIx is greater than 1.0, the supply of the specific generation owner or owners is not needed to meet market demand and those generation owners have a reduced ability to unilaterally influence market price.

45 See OATT Attachment DD § 6.5.

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

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

Table 5-9 RSI results: 2018/2019 through 2021/2022 RPM Auctions[48]

RPM Markets	$RSI_{1,\ 1.05}$	RSI_3	Total Participants	Failed RSI_3 Participants
2018/2019 Base Residual Auction				
RTO	0.81	0.65	125	125
EMAAC	0.59	0.16	12	12
ComEd	1.11	0.02	4	4
2018/2019 First Incremental Auction				
RTO	0.51	0.23	32	32
EMAAC	0.00	0.00	2	2
ComEd	0.00	0.00	1	1
2018/2019 Second Incremental Auction				
RTO	0.64	0.87	44	9
EMAAC	0.25	0.06	5	5
2018/2019 Third Incremental Auction				
RTO	0.88	0.65	71	71
EMAAC	0.00	0.00	3	3
2019/2020 Base Residual Auction				
RTO	0.81	0.66	131	131
EMAAC	0.79	0.23	6	6
ComEd	0.74	0.12	6	6
BGE	0.00	0.00	1	1
2019/2020 First Incremental Auction				
RTO	0.63	0.50	53	53
EMAAC	0.00	0.00	5	5
2019/2020 Second Incremental Auction				
RTO	0.61	0.48	38	38
BGE	0.00	0.00	1	1
2020/2021 Base Residual Auction				
RTO	0.81	0.69	119	119
MAAC	0.67	0.77	24	24
EMAAC	0.45	0.18	21	21
ComEd	0.47	0.20	14	14
DEOK	0.00	0.00	1	1
2020/2021 First Incremental Auction				
RTO	0.47	0.42	47	47
2021/2022 Base Residual Auction				
RTO	0.80	0.68	122	122
EMAAC	0.71	0.22	14	14
PSEG	0.20	0.01	5	5
ATSI	0.01	0.00	2	2
ComEd	0.08	0.02	5	5
BGE	0.23	0.00	3	3

Locational Deliverability Areas (LDAs)

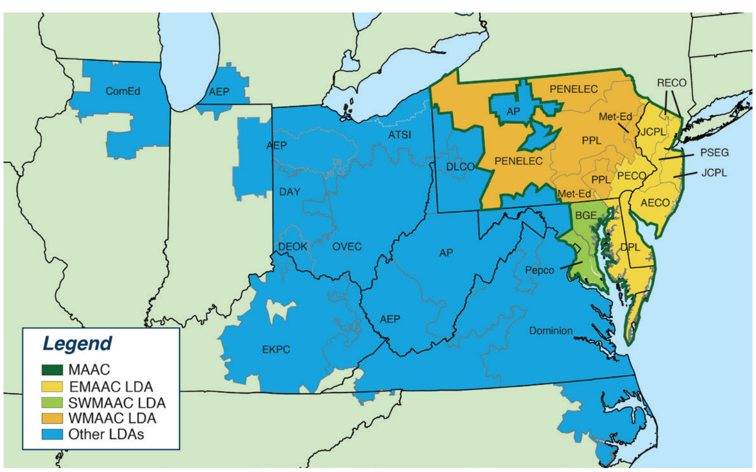
Under the PJM Tariff, PJM determines, in advance of each BRA, whether defined Locational Deliverability Areas (LDAs) will be modeled in the auction. Effective with the 2012/2013 Delivery Year, an LDA is modeled as a potentially constrained LDA for a Delivery Year if the Capacity Emergency Transfer Limit (CETL) is less than

48 The RSI shown is the lowest RSI in the market.

1.15 times the Capacity Emergency Transfer Objective (CETO), such LDA had a locational price adder in one or more of the three immediately preceding BRAs, or such LDA is determined by PJM in a preliminary analysis to be likely to have a locational price adder based on historic offer price levels. The rules also provide that starting with the 2012/2013 Delivery Year, EMAAC, SWMAAC, and MAAC LDAs are modeled as potentially constrained LDAs regardless of the results of the above three tests.[49] In addition, PJM may establish a constrained LDA even if it does not qualify under the above tests if PJM finds that "such is required to achieve an acceptable level of reliability."[50] A reliability requirement and a Variable Resource Requirement (VRR) curve are established for each modeled LDA. Effective for the 2014/2015 through 2016/2017 Delivery Years, a Minimum Annual and a Minimum Extended Summer Resource Requirement are established for each modeled LDA. Effective for the 2017/2018 Delivery Year, Sub-Annual and Limited Resource Constraints, replacing the Minimum Annual and a Minimum Extended Summer Resource Requirements, are established for each modeled LDA.[51] Effective for the 2018/2019 through the 2019/2020 Delivery Years, Base Capacity Demand Resource Constraint and a Base Capacity Resource Constraint, replacing the Sub-Annual and Limited Resource Constraints, are established for each modeled LDA.

Locational Deliverability Areas are shown in Figure 5-4, Figure 5-5 and Figure 5-6.

Figure 5-4 Map of locational deliverability areas



49 Prior to the 2012/2013 Delivery Year, an LDA with a CETL less than 1.05 times CETO was modeled as a constrained LDA in RPM. No additional criteria were used in determining modeled LDAs.

50 OATT Attachment DD § 5.10 (a) (ii).

51 146 FERC ¶ 61,052 (2014).

Figure 5-5 Map of RPM EMAAC subzonal LDAs

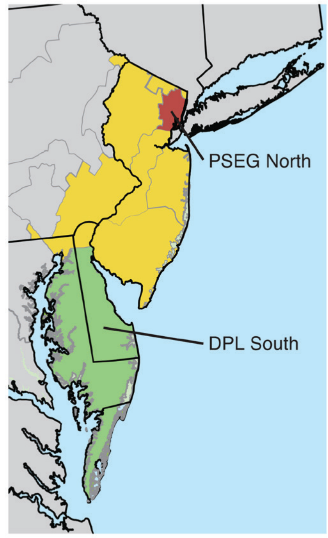
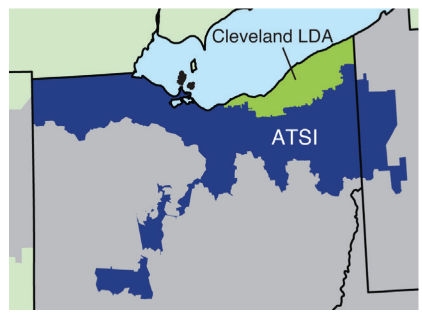


Figure 5-6 Map of RPM ATSI subzonal LDA



Imports and Exports

Units external to the metered boundaries of PJM can qualify as PJM capacity resources if they meet the requirements to be capacity resources. Generators on the PJM system that do not have a commitment to serve PJM loads in the given delivery year as a result of RPM auctions, FRR capacity plans, locational UCAP transactions, and/or are not designated as a replacement resource, are eligible to export their capacity from PJM.[52]

The PJM market rules should not create inappropriate barriers to either the import or export of capacity. The market rules in other balancing authorities should also not create inappropriate barriers to the import or export

52 OATT Attachment DD § 5.6.6(b).

of capacity. The PJM market rules should ensure that the definition of capacity is enforced including physical deliverability, recallability and the obligation to make competitive offers into the PJM Day-Ahead Energy Market. Physical deliverability can only be assured by requiring that all imports are deliverable to PJM load to ensure that they are full substitutes for internal capacity resources. While pseudo ties were a step toward this goal, pseudo ties alone are not adequate to ensure deliverability. Pseudo ties create potential issues in the exporting area and do not ensure deliverability into the importing area. Selling capacity into the PJM Capacity Market but making energy offers daily of $999 per MWh would not fulfill the requirements of a capacity resource to make a competitive offer, but would constitute economic withholding. This is one of the reasons that the rules governing the obligation to make a competitive offer in the Day-Ahead Energy Market should be clarified for both internal and external resources.

For the 2017/2018 through the 2019/2020 Delivery Year, Capacity Import Limits (CILs) are established for each of the five external source zones and the overall PJM region to account for the risk that external generation resources may not be able to deliver energy during the relevant delivery year due to the curtailment of firm transmission by third parties.[53] Capacity Market Sellers may request an exception to the CIL for an external generation resource by committing that the resource will be pseudo tied prior to the start of the relevant delivery year, by demonstrating that it has long-term firm transmission service confirmed on the complete transmission path from the resource to PJM, and by agreeing to be subject to the same RPM must offer requirement as internal PJM generation resources.

Effective June 9, 2015, an external generation capacity resource must obtain an exception to the CILs to be eligible to offer as a Capacity Performance Resource, which means that effective with the 2020/2021 delivery year, CILs are no longer defined as an RPM parameter.[54]

As shown in Table 5-10, of the 4,470.4 MW of imports offered in the 2021/2022 RPM Base Residual Auction, 4,051.8 MW cleared. Of the cleared imports, 1,909.9 MW (47.1 percent) were from MISO.

Importing Capacity

Existing External Generation Capacity Resource

Generation external to the PJM region is eligible to be offered into an RPM auction if it meets specific requirements.[55] [56] Firm transmission service from the unit to the border of PJM and generation deliverability into PJM must be demonstrated prior to the start of the delivery year. In order to demonstrate generation deliverability into PJM, external generators must obtain firm point to point transmission service on the PJM OASIS from the PJM border into the PJM transmission system or by obtaining network external designated transmission service. In the event that transmission upgrades are required to establish deliverability, those upgrades must be completed by the start of the delivery year. The following are also required: the external generating unit must be in the resource portfolio of a PJM member; 12 months of NERC/GADs unit performance data must be provided to establish an EFORd; the net capability of each unit must be verified through winter and summer testing; a letter of nonrecallability must be provided to assure PJM that the energy and capacity from the unit is not recallable to any other balancing authority.

All external generation resources that have an RPM commitment or FRR capacity plan commitment or that are designated as replacement capacity must be offered in the PJM Day-Ahead Energy Market.[57]

To avoid balancing market deviations, any offer accepted in the Day-Ahead Energy Market must be scheduled to physically flow in the Real-Time Energy Market. When submitting the real-time energy market transaction, a valid NERC Tag is required, with the appropriate transmission reservations associated. External capacity transactions must designate the transaction as such when submitting the NERC Tag. This designation allows the PJM dispatch operators to identify capacity backed transactions in order to avoid curtailing them out of merit order. External capacity backed transactions are

53 147 FERC ¶ 61,060 (2014).
54 151 FERC ¶ 61,208 (2015).

55 See "Reliability Assurance Agreement Among Load Serving Entities in the PJM Region," Schedule 9 & 10.
56 See "PJM Manual 18: PJM Capacity Market," § 4.2.2 Existing Generation Capacity Resources – External, § 4.2.4 Planned Generation Capacity Resources – External, § 4.6.4 Importing an External Generation Resource, Rev. 41 (Jan. 1, 2019).
57 OATT Schedule 1 § 1.10.1A.

evaluated the same way as all other energy transactions and are subject to all scheduling timing requirements and PJM interchange ramp limits. If the offer is not accepted in the Day-Ahead Energy Market, but the unit is requested during the operating day, the PJM dispatch operator will notify the participant. The market participant will then submit a tag to match the request. This tag will also be subject to all scheduling timing requirements and PJM interchange ramp limits.

Planned External Generation Capacity Resource

Planned external generation capacity resources are eligible to be offered into an RPM auction if they meet specific requirements.[58] [59] Planned external generation capacity resources are proposed generation capacity resources, or a proposed increase in the capability of an existing generation capacity resource, that is located outside the PJM region; participates in the generation interconnection process of a balancing authority external to PJM; is scheduled to be physically and electrically interconnected to the transmission facilities of such balancing authority on or before the first day of the delivery year for which the resource is to be committed to satisfy the reliability requirements of the PJM Region; and is in full commercial operation prior to the first day of the delivery year.[60] An external generation capacity resource becomes an existing generation capacity resource as of the earlier of the date that interconnection service commences or the resource has cleared an RPM auction.[61]

Exporting Capacity

Nonfirm transmission can be used to export capacity from the PJM region. A generation capacity resource located in the PJM region not committed to service of PJM loads may be removed from PJM capacity resource status if the Capacity Market Seller shows that the resource has a financially and physically firm commitment to an external sale of its capacity.[62] The Capacity Market Seller must also identify the megawatt amount, export zone, and time period (in days) of the export.[63]

The MMU evaluates requests submitted by Capacity Market Sellers to export generation capacity resources, makes a determination as to whether the resource meets the applicable criteria to export, and must inform both the Capacity Market Seller and PJM of such determination.[64]

When submitting a real-time market export capacity transaction, a valid NERC Tag is required, with the appropriate transmission reservations associated. Capacity transactions must designate the transaction as capacity when submitting the NERC Tag. This designation allows the PJM dispatch operators to identify capacity backed transactions in order to avoid curtailing them out of merit order. External capacity backed transactions are evaluated the same way as all other energy transactions and are subject to all scheduling timing requirements and PJM interchange ramp limits.

Table 5-10 RPM imports: 2007/2008 through 2021/2022 RPM Base Residual Auctions

	UCAP (MW)					
	MISO		Non-MISO		Total Imports	
Base Residual Auction	Offered	Cleared	Offered	Cleared	Offered	Cleared
2007/2008	1,073.0	1,072.9	547.9	547.9	1,620.9	1,620.8
2008/2009	1,149.4	1,109.0	517.6	516.8	1,667.0	1,625.8
2009/2010	1,189.2	1,151.0	518.8	518.1	1,708.0	1,669.1
2010/2011	1,194.2	1,186.6	539.8	539.5	1,734.0	1,726.1
2011/2012	1,862.7	1,198.6	3,560.0	3,557.5	5,422.7	4,756.1
2012/2013	1,415.9	1,298.8	1,036.7	1,036.7	2,452.6	2,335.5
2013/2014	1,895.1	1,895.1	1,358.9	1,358.9	3,254.0	3,254.0
2014/2015	1,067.7	1,067.7	1,948.8	1,948.8	3,016.5	3,016.5
2015/2016	1,538.7	1,538.7	2,396.6	2,396.6	3,935.3	3,935.3
2016/2017	4,723.1	4,723.1	2,770.6	2,759.6	7,493.7	7,482.7
2017/2018	2,624.3	2,624.3	2,320.4	1,901.2	4,944.7	4,525.5
2018/2019	2,879.1	2,509.1	2,256.7	2,178.8	5,135.8	4,687.9
2019/2020	2,067.3	1,828.6	2,276.1	2,047.3	4,343.4	3,875.9
2020/2021	2,511.8	1,671.2	2,450.0	2,326.0	4,961.8	3,997.2
2021/2022	2,308.4	1,909.9	2,162.0	2,141.9	4,470.4	4,051.8

58 See RAA § 1.69A.

59 See "PJM Manual 18: PJM Capacity Market," § 4.2.4 Planned Generation Capacity Resources – External, Rev. 41 (Jan. 1, 2019).

60 Prior to January 31, 2011, capacity modifications to existing generation capacity resources were not considered planned generation capacity resources. See 134 FERC ¶ 61,065 (2011).

61 Effective January 31, 2011, the RPM rules related to market power mitigation were changed, including revising the definition for Planned Generation Capacity Resource for purposes of the must-offer requirement and market power mitigation. See 134 FERC ¶ 61,065 (2011).

62 OATT Attachment DD § 6.6(g).

63 *Id.*

64 OATT Attachment M-Appendix § II.C.2.

Demand Resources

There are three basic demand products incorporated in the RPM market design:[65]

- **Demand Resources (DR).** Interruptible load resource that is offered into an RPM Auction as capacity and receives the relevant LDA or RTO resource clearing price.
- **Interruptible Load for Reliability (ILR).** Interruptible load resource that is not offered into the RPM auction, but receives the final zonal ILR price determined after the second incremental auction. The ILR product was eliminated after the 2011/2012 Delivery Year.
- **Energy Efficiency (EE) Resources.** Load resources that are offered into an RPM auction as capacity and receive the relevant LDA or RTO resource clearing price. The EE resource type was eligible to be offered in RPM auctions starting with the 2012/2013 Delivery Year and in incremental auctions in the 2011/2012 Delivery Year.[66]

Effective for the 2014/2015 through the 2017/2018 Delivery Year, there are three types of Demand Resource products included in the RPM market design:[67 68]

- **Annual DR.** A demand resource that is required to be available on any day in the relevant delivery year for an unlimited number of interruptions. Annual DR is required to be capable of maintaining each interruption for only 10 hours only during the hours of 10:00 a.m. to 10:00 p.m. EPT for the period May through October and 6:00 a.m. to 9:00 p.m. EPT for the period November through April unless there is an Office of the Interconnection approved maintenance outage during October through April.
- **Extended Summer DR.** A demand resource that is required to be available on any day from June through October and the following May in the relevant delivery year for an unlimited number of interruptions. Extended summer DR is required to be capable of maintaining each interruption for only 10 hours only during the hours of 10:00 a.m. to 10:00 p.m. EPT.
- **Limited DR.** A demand resource that is required to be available on weekdays not including NERC holidays during the period of June through September in the relevant delivery year for up to 10 interruptions. Limited DR is required to be capable of maintaining each interruption for only six hours only during the hours of 12:00 p.m. to 8:00 p.m. EPT.

Effective for the 2018/2019 and the 2019/2020 Delivery Years, there are two types of demand resource and energy efficiency resource products included in the RPM market design:[69 70]

- **Base Capacity Resources**
  - **Base Capacity Demand Resources.** A demand resource that is required to be available on any day from June through September for an unlimited number of interruptions. Base capacity DR is required to be capable of maintaining each interruption for at least 10 hours only during the hours of 10:00 a.m. to 10:00 p.m. EPT.
  - **Base Capacity Energy Efficiency Resources.** A project designed to achieve a continuous (during summer peak periods) reduction in electric energy consumption that is not reflected in the peak load forecast for the delivery year for which the base capacity energy efficiency resource is proposed, and that is fully implemented at all times during the relevant delivery year, without any requirement of notice, dispatch, or operator intervention. The peak period definition for the base capacity energy efficiency resource type includes the period from the hour ending 15:00 EPT and the hour ending 18:00 EPT from June through August, excluding weekends and federal holidays.
- **Capacity Performance Resources**
  - **Annual Demand Resources.** A demand resource that is required to be available on any day in the relevant delivery year for an unlimited number of interruptions. Annual DR is required to be capable of maintaining each interruption for only 10 hours during the hours of 10:00 a.m. to 10:00

65 Effective June 1, 2007, the PJM active load management (ALM) program was replaced by the PJM load management (LM) program. Under ALM, providers had received a MW credit which offset their capacity obligation. With the introduction of LM, qualifying load management resources can be offered into RPM auctions as capacity resources and receive the clearing price.

66 Letter Order in Docket No. ER10-366-000 (January 22, 2010).

67 134 FERC ¶ 61,066 (2011).

68 "Reliability Assurance Agreement among Load-Serving Entities in the PJM Region," Article 1.

69 151 FERC ¶ 61,208.

70 "Reliability Assurance Agreement Among Load Serving Entities in the PJM Region," Article 1.

p.m. EPT for the period May through October and 6:00 a.m. to 9:00 p.m. EPT for the period November through April unless there is an Office of the Interconnection approved maintenance outage during October through April.

- **Annual Energy Efficiency Resources.** A project designed to achieve a continuous (during summer and winter peak periods) reduction in electric energy consumption during peak periods that is not reflected in the peak load forecast for the delivery year for which the energy efficiency resource is proposed, and that is fully implemented at all times during the relevant delivery year, without any requirement of notice, dispatch, or operator intervention. The peak period definition for the annual energy efficiency resource type includes the period from the hour ending 15:00 EPT and the hour ending 18:00 EPT from June through August, and the period from the hour ending 8:00 EPT and the hour ending 9:00 EPT and the period from the hour ending 19:00 EPT and the hour ending 20:00 EPT from January through February, excluding weekends and federal holidays.

Effective with the 2020/2021 Delivery Year, the Capacity Performance Product will be the only capacity product type, with two possible season types, annual and summer.

- **Annual Capacity Performance Resources**
  - Annual Demand Resources
  - Annual Energy Efficiency Resources
- **Seasonal Capacity Performance Resources**
  - **Summer-Period Demand Resources.** A demand resource that is required to be available on any day from June through October and the following May of the delivery year for an unlimited number of interruptions. Summer period DR is required to be capable of maintaining each interruption between the hours of 10:00 a.m. to 10:00 p.m. EPT.
  - **Summer-Period Energy Efficiency Resources.** A project designed to achieve a continuous (during summer peak periods) reduction in electric energy consumption during peak periods that is not reflected in the peak load forecast for the delivery year for which the energy efficiency resource is proposed, and that is fully implemented at all times during the relevant delivery year, without any requirement of notice, dispatch, or operator intervention. The peak period definition for the summer-period efficiency resource type includes the period from the hour ending 15:00 EPT and the hour ending 18:00 EPT from June through August, excluding weekends and federal holidays.

As shown in Table 5-11, Table 5-12, and Table 5-13, capacity in the RPM load management programs was 10,798.7 MW for June 1, 2018, as a result of cleared capacity for demand resources and energy efficiency resources in RPM auctions for the 2018/2019 Delivery Year (13,731.7 MW) less replacement capacity (2,933.0 MW).

Table 5-11 RPM load management statistics by LDA: June 1, 2017 to June 1, 2021[71][72][73][74]

		UCAP (MW)														
		RTO	MAAC	EMAAC	SWMAAC	DPL South	PSEG	PSEG North	Pepco	ATSI	ATSI Cleveland	ComEd	BGE	PPL	DAY	DEOK
01-Jun-17	DR cleared	11,870.7	4,584.5	1,630.9	1,464.1	86.3	402.8	157.1	658.3	1,256.0	323.5	1,602.9	805.8	811.9		
	EE cleared	1,922.3	547.7	180.0	291.5	5.6	55.2	18.5	155.4	192.3	41.4	747.6	136.1	43.2		
	DR net replacements	(3,870.8)	(1,461.6)	(555.7)	(344.8)	(39.5)	(107.9)	(30.6)	(136.5)	(457.2)	(163.1)	(279.2)	(208.3)	(299.2)		
	EE net replacements	195.6	145.8	20.6	98.3	(0.4)	4.4	2.6	26.2	(41.9)	(11.7)	10.3	72.1	(9.9)		
	Total RPM load management	10,117.8	3,816.4	1,275.8	1,509.1	52.0	354.5	147.6	703.4	949.2	190.1	2,081.6	805.7	546.0		
01-Jun-18	DR cleared	11,435.4	4,361.9	1,707.2	1,226.4	86.8	389.9	139.2	559.3	1,034.3	287.2	1,895.2	667.1	716.2		
	EE cleared	2,296.3	706.8	315.9	317.6	9.2	102.0	45.2	186.1	184.4	33.2	807.4	131.5	43.1		
	DR net replacements	(3,181.8)	(1,268.4)	(584.3)	(199.5)	(52.4)	(150.9)	(43.6)	(25.6)	(261.0)	(136.7)	(430.0)	(173.9)	(220.0)		
	EE net replacements	248.8	163.0	45.5	107.6	1.1	22.4	9.1	(8.9)	14.7	4.7	29.0	116.5	5.4		
	Total RPM load management	10,798.7	3,963.3	1,484.3	1,452.1	44.7	363.4	149.9	710.9	972.4	188.4	2,301.6	741.2	544.7		
01-Jun-19	DR cleared	10,422.7	3,810.5	1,650.7	758.9	91.3	381.1	176.5	496.5	906.3	289.9	1,757.4	262.4	739.8		
	EE cleared	2,198.2	675.8	297.2	272.5	5.4	94.1	33.3	151.3	188.1	39.6	750.1	121.2	62.9		
	DR net replacements	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0		
	EE net replacements	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0		
	Total RPM load management	12,620.9	4,486.3	1,947.9	1,031.4	96.7	475.2	209.8	647.8	1,094.4	329.5	2,507.5	383.6	802.7		
01-Jun-20	DR cleared	9,008.7	2,823.2	1,168.9	481.1	72.6	339.0	152.7	234.6	853.0	227.1	1,623.0	246.5	615.6	211.4	164.1
	EE cleared	2,080.5	683.7	346.7	261.4	8.7	119.6	38.7	114.2	172.0	40.1	722.6	147.2	44.2	53.8	74.1
	DR net replacements	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	EE net replacements	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Total RPM load management	11,089.2	3,506.9	1,515.6	742.5	81.3	458.6	191.4	348.8	1,025.0	267.2	2,345.6	393.7	659.8	265.2	238.2
01-Jun-21	DR cleared	11,125.8	3,413.4	1,378.9	624.9	66.3	407.9	188.6	345.9	1,142.4	272.8	1,997.8	279.0	684.7	227.7	213.8
	EE cleared	2,832.0	938.7	617.0	207.0	13.6	240.1	72.9	102.6	148.2	36.2	770.5	104.4	72.4	60.1	89.7
	DR net replacements	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	EE net replacements	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Total RPM load management	13,957.8	4,352.1	1,995.9	831.9	79.9	648.0	261.5	448.5	1,290.6	309.0	2,768.3	383.4	757.1	287.8	303.5

Table 5-12 RPM commitments, replacements, and registrations for demand resources: June 1, 2007 to June 1, 2021[75][76][77]

	UCAP (MW)						Registered DR		
	RPM Cleared	Adjustments to Cleared	Net Replacements	RPM Commitments	RPM Commitment Shortage	RPM Commitments Less Commitment Shortage	ICAP (MW)	UCAP Conversion Factor	UCAP (MW)
01-Jun-07	127.6	0.0	0.0	127.6	0.0	127.6	0.0	1.033	0.0
01-Jun-08	559.4	0.0	(40.0)	519.4	(58.4)	461.0	488.0	1.034	504.7
01-Jun-09	892.9	0.0	(474.7)	418.2	(14.3)	403.9	570.3	1.033	589.2
01-Jun-10	962.9	0.0	(516.3)	446.6	(7.7)	438.9	572.8	1.035	592.6
01-Jun-11	1,826.6	0.0	(1,052.4)	774.2	0.0	774.2	1,117.9	1.035	1,156.5
01-Jun-12	8,752.6	(11.7)	(2,253.6)	6,487.3	(34.9)	6,452.4	7,443.7	1.037	7,718.4
01-Jun-13	10,779.6	0.0	(3,314.4)	7,465.2	(30.5)	7,434.7	8,240.1	1.042	8,586.8
01-Jun-14	14,943.0	0.0	(6,731.8)	8,211.2	(219.4)	7,991.8	8,923.4	1.042	9,301.2
01-Jun-15	15,774.8	(321.1)	(4,829.7)	10,624.0	(61.8)	10,562.2	10,946.0	1.038	11,360.0
01-Jun-16	13,284.7	(19.4)	(4,800.7)	8,464.6	(455.4)	8,009.2	8,961.2	1.042	9,333.4
01-Jun-17	11,870.7	0.0	(3,870.8)	7,999.9	(30.3)	7,969.6	8,681.4	1.039	9,016.3
01-Jun-18	11,435.4	0.0	(3,181.8)	8,253.6		8,252.6	8,512.0	1.091	9,282.4
01-Jun-19	10,422.7	0.0	0.0	10,422.7	0.0	10,422.7	0.0	1.090	0.0
01-Jun-20	9,008.7	0.0	0.0	9,008.7	0.0	9,008.7	0.0	1.090	0.0
01-Jun-21	11,125.8	0.0	0.0	11,125.8	0.0	11,125.8	0.0	1.090	0.0

71 See OATT Attachment DD § 8.4. The reported DR cleared MW may reflect reductions in the level of committed MW due to relief from Capacity Resource Deficiency Charges.

72 Pursuant to OA § 15.1.6(c), PJM Settlement shall attempt to close out and liquidate forward capacity commitments for PJM Members that are declared in collateral default. The replacement transactions reported for the 2014/2015 Delivery Year include transactions associated with RTP Controls, Inc., which was declared in collateral default on March 9, 2012.

73 See OATT Attachment DD § 5.14C. The reported DR cleared MW for the 2015/2016 and 2016/2017 Delivery Years reflect reductions in the level of committed MW due to the Demand Response Operational Resource Flexibility Transition Provision.

74 See OATT Attachment DD § 5.14E. The reported DR cleared MW for the 2016/2017, 2017/2018, and 2018/2019 Delivery Years reflect reductions in the level of committed MW due to the Demand Response Legacy Direct Load Control Transition Provision.

75 See OATT Attachment DD § 8.4. The reported DR adjustments to cleared MW include reductions in the level of committed MW due to relief from Capacity Resource Deficiency Charges.

76 See OATT Attachment DD § 5.14C. The reported DR adjustments to cleared MW for the 2015/2016 and 2016/2017 Delivery Years include reductions in the level of committed MW due to the Demand Response Operational Resource Flexibility Transition Provision.

77 See OATT Attachment DD § 5.14E. The reported DR adjustments to cleared MW for the 2016/2017, 2017/2018, and 2018/2019 Delivery Years include reductions in the level of committed MW due to the Demand Response Legacy Direct Load Control Transition Provision.

Table 5-13 RPM commitments and replacements for energy efficiency resources: June 1, 2007 to June 1, 2021[78]

	UCAP (MW)					
	RPM Cleared	Adjustments to Cleared	Net Replacements	RPM Commitments	RPM Commitment Shortage	RPM Commitments Less Commitment Shortage
01-Jun-07	0.0	0.0	0.0	0.0	0.0	0.0
01-Jun-08	0.0	0.0	0.0	0.0	0.0	0.0
01-Jun-09	0.0	0.0	0.0	0.0	0.0	0.0
01-Jun-10	0.0	0.0	0.0	0.0	0.0	0.0
01-Jun-11	76.4	0.0	0.2	76.6	0.0	76.6
01-Jun-12	666.1	0.0	(34.9)	631.2	(5.1)	626.1
01-Jun-13	904.2	0.0	120.6	1,024.8	(13.5)	1,011.3
01-Jun-14	1,077.7	0.0	204.7	1,282.4	(0.2)	1,282.2
01-Jun-15	1,189.6	0.0	335.9	1,525.5	(0.9)	1,524.6
01-Jun-16	1,723.2	0.0	61.1	1,784.3	(0.5)	1,783.8
01-Jun-17	1,922.3	0.0	195.6	2,117.9	(7.4)	2,110.5
01-Jun-18	2,296.3	0.0	248.8	2,545.1	0.0	2,545.1
01-Jun-19	2,198.2	0.0	0.0	2,198.2	0.0	2,198.2
01-Jun-20	2,080.5	0.0	0.0	2,080.5	0.0	2,080.5
01-Jun-21	2,832.0	0.0	0.0	2,832.0	0.0	2,832.0

Market Conduct

Offer Caps and Offer Floors

Market power mitigation measures were applied to capacity resources such that the sell offer was set equal to the defined offer cap when the Capacity Market Seller failed the market structure test for the auction, the submitted sell offer exceeded the defined offer cap, and the submitted sell offer, absent mitigation, would have increased the market clearing price.[79 80 81] For Base Capacity, offer caps are defined in the PJM Tariff as avoidable costs less PJM market revenues, or opportunity costs based on the potential sale of capacity in an external market. For Capacity Performance Resources, offer caps are defined in the PJM Tariff as the applicable zonal net Cost of New Entry (CONE) times (B) where B is the average of the Balancing Ratios (B) during the Performance Assessment Hours in the three consecutive calendar years that precede the base residual auction for such delivery year unless net avoidable costs exceed this level, or opportunity costs based on the potential sale of capacity in an external market. For RPM Third Incremental Auctions, capacity market sellers may elect, for Base Capacity offers, an offer cap equal to 1.1 times the BRA clearing price for the relevant LDA and delivery year or, for Capacity Performance offers, an offer cap equal to the greater of the net CONE for the relevant LDA and delivery year or 1.1 times the BRA clearing price for the relevant LDA and delivery year.

Avoidable costs are the costs that a generation owner would not incur if the generating unit did not operate for one year, in particular the delivery year.[82] In the calculation of avoidable costs, there is no presumption that the unit would retire as the alternative to operating, although that possibility could be reflected if the owner documented that retirement was the alternative. Avoidable costs may also include annual capital recovery associated with investments required to maintain a unit as a generation capacity resource, termed Avoidable Project Investment Recovery (APIR). Avoidable cost based offer caps are defined to be net of revenues from all other PJM markets and unit-specific bilateral contracts. For Capacity Performance Resources, avoidable cost based offer caps are defined to be net of revenues from all other PJM markets and unit-specific bilateral contracts and expected bonus performance payments/non-performance charges.[83] Capacity resource owners could provide ACR data by providing their own unit-specific data or, for delivery years prior to 2020/2021, by selecting the default ACR values. The specific components of avoidable costs are defined in the PJM Tariff.[84]

Effective for the 2018/2019 and subsequent delivery years, the ACR definition includes two additional components, Avoidable Fuel Availability Expenses (AFAE) and Capacity Performance Quantifiable Risk

78 Pursuant to PJM Operating Agreement § 15.1.6(c), PJM Settlement shall attempt to close out and liquidate forward capacity commitments for PJM members that are declared in collateral default. The replacement transactions reported for the 2014/2015 Delivery Year included transactions associated with RTP Controls, Inc., which was declared in collateral default on March 9, 2012.

79 See OATT Attachment DD § 6.5.

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

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

82 OATT Attachment DD § 6.8 (b).

83 For details on the competitive offer of a capacity performance resource, see "Analysis of the 2021/2022 RPM Base Residual Auction - Revised," <http://www.monitoringanalytics.com/reports/Reports/2018/IMM_Analysis_of_the_20212022_RPM_BRA_Revised_20180824.pdf> (August 24, 2018).

84 OATT Attachment DD § 6.8 (a).

(CPQR).[85] AFAE is available for Capacity Performance Resources. AFAE is defined to include expenses related to fuel availability and delivery. CPQR is available for Capacity Performance Resources and, for the 2018/2019 and 2019/2020 Delivery Years, Base Capacity Resources. CPQR is defined to be the quantifiable and reasonably supported cost of mitigating the risks of nonperformance associated with submission of an offer.

The opportunity cost option allows Capacity Market Sellers to offer based on a documented price available in a market external to PJM, subject to export limits. If the relevant RPM market clears above the opportunity cost, the generation capacity resource is sold in the RPM market. If the opportunity cost is greater than the clearing price and the generation capacity resource does not clear in the RPM market, it is available to sell in the external market.

Calculation of Offer Caps

The competitive offer of a Capacity Performance resource is based on a market seller's expectations of a number of variables, some of which are resource specific: the resource's net going forward costs (Net ACR); and the resource's performance during performance assessment intervals (A) in the delivery year.[86]

The competitive offer of a Capacity Performance resource is also based on a market seller's expectations of system level variables: the number of performance assessment intervals (PAI) in a delivery year (H) where the resource is located; the level of performance required to meet its capacity obligation during those performance assessment hours, measured as the average Balancing Ratio (B); and the level of the bonus performance payment rate (CPBR) compared to the nonperformance charge rate (PPR). The level of bonus performance payment rate depends on the level of underperforming MW net of the underperforming MW excused by PJM during performance assessment hours for reasons defined in the PJM OATT.[87]

The default offer cap defined in the PJM tariff, Net CONE times the average Balancing Ratio, is based on a number of assumptions:

1. The Net ACR of a resource is less than its expected energy only bonuses:

$$ACR \leq \sum_{i=1}^{H} (CPBR_i \times A_i)$$

$$or\ ACR \leq \left(\frac{1}{12}\right)(CPBR \times H \times \bar{A})$$

2. The expected number of performance assessment intervals equals 360. (H = 360 intervals, or 12 hours)
3. The expected value of the bonus performance payment rate (CPBR) is equal to the nonperformance charge rate (PPR)
4. The average expected performance of the resource during performance assessment hours ($\bar{A}$)

The competitive offer of such a resource is:

$$p = \left(\frac{1}{12}\right)(CPBR \times H \times \bar{A} + PPR \times H \times (\bar{B} - \bar{A}))$$

In other words, the competitive offer of such a resource is the opportunity cost of taking on the capacity obligation which equals the sum of the energy only bonuses it would have earned $(CPBR \times H \times \bar{A})/12$ and the net nonperformance charges it would incur by taking on the capacity obligation $(PPR \times H \times (\bar{B} - \bar{A})/12)$. Both the components are proportional to the expected number of performance assessment intervals. If the expected number of performance assessment intervals (H) is significantly lower than the value used to determine the non-performance charge rate (PPR), the opportunity of earning bonuses as an energy only resource, as well as the net non-performance charges incurred by taking on a capacity obligation are lower. Under such a scenario, the likelihood that that the resource's Net ACR is lower than the expected energy only bonuses is reduced. For resources whose Net ACR is greater than the expected energy only bonuses, the competitive offer is the Net ACR adjusted with any capacity performance bonuses or non-performance charges they expect to incur during the delivery year.

This means that when the expected number of performance assessment intervals are lower than the value used to determine the non-performance charge

85 151 FERC ¶ 61,208.
86 The model is only applicable to generation resources and storage resources that have an annual obligation to perform with very limited specific excuses as defined in the PJM OATT.
87 OATT Attachment DD § 10A (d).

rate (360 intervals, or 30 hours), the current default offer cap of Net CONE times B overstates the competitive offer and the market seller offer cap.

The recent history of a low number of emergency actions in PJM reflect the improvements to generator performance with the capacity performance design, the reduction in actual and expected pool wide outage rates as a result of new units added to the system and the retirement of old units, the upward biased peak load forecasts used in RPM, and the high reserve margins in capacity.[88] [89] Given these developments, the assumption that there would be 30 hours of emergency actions in a year that would trigger performance assessment intervals is unsupported. Since the non-performance charge rate is defined in the tariff as net CONE divided by 30 hours, the adjusted default offer cap to reflect a lower estimate for the number of PAIs is much lower than net CONE times B.

In the 2021/2022 RPM Base Residual Auction, net CONE times B exceeded the actual competitive offer level of a Low ACR resource that the default offer cap is based on.[90] While most participants offered in the 2021/2022 RPM Base Residual Auction at competitive levels based on their expectation of the number of performance assessment hours and projected net revenues, some market participants did not offer competitively and affected the market clearing prices.

MOPR

Effective April 12, 2011, the RPM Minimum Offer Price Rule (MOPR) was changed.[91] The changes to the MOPR included updating the calculation of the net Cost of New Entry (CONE) for Combined Cycle (CC) and Combustion Turbine (CT) plants which is used as a benchmark value in assessing the competitiveness of a sell offer, increasing the percentage value used in the screen to 90 percent for CC and CT plants, eliminating the net-short requirement as a prerequisite for applying the MOPR, eliminating the impact screen, revising the process for reviewing proposed exceptions to the defined minimum sell offer price, and clarifying which resources are subject to the MOPR along with the duration of mitigation. Subsequent FERC Orders revised the MOPR, including clarification on the duration of mitigation, which resources are subject to MOPR, and the MOPR review process.[92]

Effective May 3, 2013, the RPM Minimum Offer Price Rule (MOPR) was changed again.[93] The changes to the MOPR included establishing Competitive Entry and Self Supply Exemptions while also retaining the unit specific exception process for those that do not qualify for the Competitive Entry or Self Supply Exemptions; changing the applicability of MOPR to include only combustion turbine, combined cycle, integrated gasification combined cycle (IGCC) technologies while excluding units primarily fueled with landfill gas or cogeneration units which are certified or self-certified as Qualifying Facilities (QFs); changing the applicability to increases in installed capacity of 20.0 MW or more combined for all units at a single point of interconnection to the transmission system; changing the applicability to include the full capability of repowering of plants based on combustion turbine, combined cycle, IGCC technology; increasing the screen from 90 percent to 100 percent of the applicable net CONE values; and broadening the region subject to MOPR to the entire RTO from modeled LDAs only.

Effective December 8, 2017, FERC issued an order on remand rejecting PJM's MOPR proposal in Docket No. ER13-535, and as a result, the rules that were in effect prior to PJM's December 7, 2012, MOPR filing were reinstated. These changes include eliminating the Competitive Entry and Self Supply Exemptions and retaining only the Unit Specific Exception request; narrowing the region subject to MOPR from the entire RTO to only modeled LDAs; eliminating the 20.0 MW threshold for applicability; redefining the applicability criteria to exclude nuclear, coal, IGCC, hydroelectric, wind and solar facilities; modifying the duration of mitigation criteria from clearing in a prior delivery year to clearing in any delivery year; and changing the procedural deadlines.[94]

88 PJM experienced zero emergency events since April 2014, that would have triggered a PAI in an area that at least encompasses a PJM transmission zone. See "Balancing Ratio Determination Issue", at 12 <http://www.pjm.com/-/media/committees-groups/ committees/mic/20180404/20180404-item-10b1-balancing-ratio-determination-solution-options.ashx> (April 4, 2018).

89 See Table 5-7.

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

91 135 FERC ¶ 61,022 (2011).

92 135 FERC ¶ 61,022 (2011), *order on reh'g*, 137 FERC ¶ 61,145 (2011).

93 143 FERC ¶ 61,090 (2013).

94 161 FERC ¶ 61,252 (2017).

2018/2019 RPM Base Residual Auction

As shown in Table 5-14, 473 generation resources submitted Base Capacity offers in the 2018/2019 RPM Base Residual Auction. The MMU calculated offer caps for 219 generation resources (46.3 percent), of which 166 were based on the technology specific default (proxy) ACR values, 53 were unit-specific offer caps (11.2 percent of all generation resources), of which 45 included an APIR component, eight Planned Generation Capacity Resources had uncapped offers (1.7 percent), and the remaining 246 generation resources were price takers (52.0 percent). Market power mitigation was applied to the Base Capacity sell offers of 18 generation capacity resources, including 3,271.9 MW.

As shown in Table 5-14, 992 generation resources submitted Capacity Performance offers in the 2018/2019 RPM Base Residual Auction. The MMU calculated offer caps for 35 generation resources (3.5 percent), all of which were unit-specific with an APIR component, 15 Planned Generation Capacity Resources had uncapped offers (1.5 percent), and the remaining 54 generation resources were price takers (5.4 percent). Market power mitigation was applied to the Capacity Performance sell offers of zero generation resources, including 0.0 MW.

Of the 473 generation resources which submitted Base Capacity offers, 45 (9.5 percent) included an APIR component. Of the 992 generation resources which submitted Capacity Performance offers, 35 (3.5 percent) included an APIR component. As shown in Table 5-18, the weighted average gross ACR for units with APIR was $406.58 per MW-day for Base Capacity Resources and $496.37 per MW-day for Capacity Performance Resources. The weighted average offer caps, net of net revenues, for units with APIR was $321.80 per MW-day for Base Capacity Resources and $356.54 per MW-day for Capacity Performance Resources. The APIR component added to the ACR value of the APIR units an average of $281.13 per MW-day for Base Capacity Resources and $344.93 for Capacity Performance Resources. The maximum APIR effect ($1,051.98 per MW-day for Base Capacity Resources and Capacity Performance Resources) is the maximum amount by which an offer cap was increased by APIR. The CPQR component added to the ACR value of the APIR units an average of $0.00 per MW-day for Base Capacity Resources and $10.08 per MW-day for Capacity Performance Resources.

2018/2019 RPM First Incremental Auction

As shown in Table 5-14, 80 generation resources submitted Base Capacity offers in the 2018/2019 RPM First Incremental Auction. The MMU calculated offer caps for 30 generation resources (37.5 percent), of which 18 were based on the technology specific default (proxy) ACR values and 12 were unit-specific offer caps (15.0 percent of all generation resources), of which all of which included an APIR component. Of the 30 generation resources with Base Capacity offers, four Planned Generation Capacity Resources had uncapped offers (5.0 percent), and the remaining 46 generation resources were price takers (57.5 percent). Market power mitigation was applied to the Base Capacity sell offers of three generation resources, including 8.2 MW.

As shown in Table 5-14, 293 generation resources submitted Capacity Performance offers in the 2018/2019 RPM First Incremental Auction. The MMU calculated offer caps for nine generation resources (3.1 percent), all of which were unit-specific with an APIR component. Of the 293 generation resources, 261 generation resources had the net CONE times B offer cap (89.1 percent), seven Planned Generation Capacity Resources had uncapped offers (2.4 percent), one generation resource had an uncapped planned uprate plus net CONE times B offer cap for the existing portion of the unit (0.3 percent), and the remaining 15 generation resources were price takers (5.1 percent). Market power mitigation was applied to the Capacity Performance sell offers of zero generation resources, including 0.0 MW.

2018/2019 RPM Second Incremental Auction

As shown in Table 5-14, 68 generation resources submitted Base Capacity offers in the 2018/2019 RPM Second Incremental Auction. The MMU calculated offer caps for 23 generation resources (33.8 percent), of which 12 were based on the technology specific default (proxy) ACR values and 11 were unit-specific offer caps (16.2 percent of all generation resources), of which all included an APIR component. Of the 68 generation resources with Base Capacity offers, six Planned Generation Capacity Resources had uncapped offers (8.8 percent), and the remaining 39 generation resources were price takers (57.4 percent). Market power mitigation was applied to the Base Capacity sell offers of zero generation resources, including 0.0 MW.

As shown in Table 5-14, 344 generation resources submitted Capacity Performance offers in the 2018/2019 RPM Second Incremental Auction. The MMU calculated offer caps for five generation resources (1.5 percent), all of which were unit-specific with an APIR component. Of the 344 generation resources, 327 generation resources had the net CONE times B offer cap (95.1 percent), four Planned Generation Capacity Resources had uncapped offers (1.2 percent), and the remaining eight generation resources were price takers (2.3 percent). Market power mitigation was applied to the Capacity Performance sell offers of zero generation resources, including 0.0 MW.

2018/2019 RPM Third Incremental Auction

As shown in Table 5-14, 211 generation resources submitted Base Capacity offers in the 2018/2019 RPM Third Incremental Auction. The MMU calculated offer caps for five generation resources (2.4 percent), of which one was based on the technology specific default (proxy) ACR values and four were unit-specific offer caps (1.9 percent of all generation resources), of which all included an APIR component. Of the 211 generation resources with Base Capacity offers, 137 generation resources elected the offer cap option of 1.1 times the BRA clearing price (64.9 percent), five Planned Generation Capacity Resources had uncapped offers (2.4 percent), and the remaining 64 generation resources were price takers (30.3 percent). Market power mitigation was applied to the Base Capacity sell offers of zero generation resources, including 0.0 MW.

As shown in Table 5-14, 495 generation resources submitted Capacity Performance offers in the 2018/2019 RPM Third Incremental Auction. The MMU calculated offer caps for three generation resources (06 percent), all of which were unit-specific with an APIR component. Of the 495 generation resources, 364 generation resources had the net CONE times B offer cap (73.5 percent), 98 generation resources elected the offer cap option of 1.1 times the BRA clearing price (19.8 percent), two Planned Generation Capacity Resources had uncapped offers (0.4 percent), and the remaining 28 generation resources were price takers (5.7 percent). Market power mitigation was applied to the Capacity Performance sell offers of zero generation resources, including 0.0 MW.

2019/2020 RPM Base Residual Auction

As shown in Table 5-15, 505 generation resources submitted Base Capacity offers in the 2019/2020 RPM Base Residual Auction. The MMU calculated offer caps for 212 generation resources (42.0 percent), of which 171 were based on the technology specific default (proxy) ACR values and 41 were unit-specific offer caps (8.1 percent of all generation resources), of which 34 included an APIR component. Of the 505 generation resources, nine Planned Generation Capacity Resources had uncapped offers (1.8 percent), and the remaining 284 generation resources were price takers (56.2 percent). Market power mitigation was applied to the Base Capacity sell offers of 34 generation resources, including 3,116.5 MW.

As shown in Table 5-15, 1,003 generation resources submitted Capacity Performance offers in the 2019/2020 RPM Base Residual Auction. The MMU calculated offer caps for 25 generation resources (2.5 percent), all of which were unit-specific with an APIR component. Of the 1,003 generation resources, 888 generation resources had the net CONE times B offer cap (88.5 percent), 14 Planned Generation Capacity Resources had uncapped offers (1.4 percent), two generation resources had uncapped planned uprates plus net CONE times B offer cap for the existing portion of the units (0.2 percent), and the remaining 74 generation resources were price takers (5.4 percent). Market power mitigation was applied to the Capacity Performance sell offers of three generation resources, including 50.8 MW.

Of the 505 generation resources which submitted Base Capacity offers, 34 (6.7 percent) included an APIR component. Of the 1,003 generation resources which submitted Capacity Performance offers, 25 (2.5 percent) included an APIR component. As shown in Table 5-19, the weighted average gross ACR for units with APIR was $341.40 per MW-day for Base Capacity Resources and $499.18 per MW-day for Capacity Performance Resources. The weighted average offer caps, net of net revenues, for units with APIR was $271.22 per MW-day for Base Capacity Resources and $323.27 per MW-day for Capacity Performance Resources. The APIR component added to the ACR value of the APIR units an average of $230.67 per MW-day for Base Capacity Resources and $375.38 for Capacity Performance Resources. The maximum APIR effect ($1,104.93 per MW-day for

Base Capacity Resources and Capacity Performance Resources) is the maximum amount by which an offer cap was increased by APIR. The CPQR component added to the ACR value of the APIR units an average of $0.00 per MW-day for Base Capacity Resources and $1.53 per MW-day for Capacity Performance Resources.

2019/2020 RPM First Incremental Auction

As shown in Table 5-15, 81 generation resources submitted Base Capacity offers in the 2019/2020 RPM First Incremental Auction. The MMU calculated offer caps for 28 generation resources (34.6 percent), of which 17 were based on the technology specific default (proxy) ACR values and 11 were unit-specific offer caps (13.6 percent of all generation resources), of which all included an APIR component. Of the 81 generation resources with Base Capacity offers, the remaining 53 generation resources were price takers (65.4 percent). Market power mitigation was applied to the Base Capacity sell offers of zero generation resources, including 0.0 MW.

As shown in Table 5-15, 382 generation resources submitted Capacity Performance offers in the 2019/2020 RPM First Incremental Auction. The MMU calculated offer caps for seven generation resources (1.8 percent), of which six were unit-specific with an APIR component and one was based on the technology specific default (proxy) ACR value. Of the 382 generation resources, 362 generation resources had the net CONE times B offer cap (94.8 percent), one Planned Generation Capacity Resource had an uncapped offer (0.3 percent), one generation resource had an uncapped planned uprate plus price taker status for the existing portion of the unit (0.3 percent), and the remaining 11 generation resources were price takers (2.9 percent). Market power mitigation was applied to the Capacity Performance sell offers of zero generation resources, including 0.0 MW.

2019/2020 RPM Second Incremental Auction

As shown in Table 5-15, 72 generation resources submitted Base Capacity offers in the 2019/2020 RPM Second Incremental Auction. The MMU calculated offer caps for 18 generation resources (25.0 percent), of which 10 were based on the technology specific default (proxy) ACR values and 8 were unit-specific offer caps (11.1 percent of all generation resources), of which all included an APIR component. Of the 72 generation resources with Base Capacity offers, two Planned Generation Capacity Resources had uncapped offers (2.8 percent), one generation resource had an uncapped planned uprate price taker for the existing portion of the unit, and the remaining 51 generation resources were price takers (70.8 percent). Market power mitigation was applied to the Base Capacity sell offers of one generation resource, including 0.1 MW.

As shown in Table 5-15, 409 generation resources submitted Capacity Performance offers in the 2019/2020 RPM Second Incremental Auction. The MMU calculated offer caps for six generation resources (1.5 percent), all of which were unit-specific including one generation resource (0.2 percent) with an Avoidable Project Investment Recovery Rate (APIR) and a CPQR component and five generation resources (1.2 percent) with an APIR component and no CPQR component. Of the 409 generation resources, 350 generation resources had the net CONE times B offer cap (85.6 percent), three generation resources had uncapped planned uprates plus net CONE times B offer cap for the existing portion of the units, one generation resource had uncapped planned uprates and price taker for the existing portion of the unit, and the remaining 49 generation resources were price takers (12.0 percent). Market power mitigation was applied to the Capacity Performance sell offers of one generation resource, including 0.2 MW.

2020/2021 RPM Base Residual Auction

As shown in Table 5-16, 1,114 generation resources submitted Capacity Performance offers in the 2020/2021 RPM Base Residual Auction. The MMU calculated offer caps for 14 generation resources that submitted Capacity Performance offers. Unit-specific ACR-based offer caps were calculated for 14 generation resources (1.3 percent) including 11 generation resources (1.0 percent) with an Avoidable Project Investment Recovery Rate (APIR) and a CPQR component and three generation resources (0.3 percent) with an APIR component and no CPQR component. Of the 1,114 generation resources offered as Capacity Performance, 956 generation resources had the net CONE times B offer cap, zero generation resources had opportunity cost-based offer caps, 12 Planned Generation Capacity Resources had uncapped offers, 18 generation resources had uncapped planned uprates plus net CONE times B offer cap for the existing portion of the units, two generation resource had an uncapped planned uprate plus price taker status for the existing portion of the unit, while the remaining 112 generation resources were price takers. Market power mitigation was applied to the sell offers of zero generation resources, including 0.0 MW.

Of the 1,114 generation resources which submitted Capacity Performance offers, 14 (1.3 percent) included an APIR component. As shown in Table 5-20, the weighted average gross ACR for units with APIR was $498.15 per MW-day for Capacity Performance Resources. The weighted average offer caps, net of net revenues, for units with APIR was $209.18 per MW-day for Capacity Performance Resources. The APIR component added to the ACR value of the APIR units an average of $235.67 per MW-day for Capacity Performance Resources. The maximum APIR effect ($464.71 per MW-day for Capacity Performance Resources) is the maximum amount by which an offer cap was increased by APIR. The CPQR component added to the ACR value of the APIR units an average of $0.23 per MW-day for Capacity Performance Resources.

2020/2021 RPM First Incremental Auction

As shown in Table 5-16, 397 generation resources submitted Capacity Performance offers in the 2020/2021 RPM First Incremental Auction. The MMU calculated offer caps for eight generation resources that submitted Capacity Performance offers. Unit-specific ACR-based offer caps were calculated for eight generation resources (2.0 percent) including seven generation resources (1.8 percent) with an Avoidable Project Investment Recovery Rate (APIR) and a CPQR component and one generation resources (0.3 percent) with an APIR component and no CPQR component. Of the 397 generation resources offered as Capacity Performance, 371 generation resources had the net CONE times B offer cap, zero generation resources had opportunity cost-based offer caps, six Planned Generation Capacity Resources had uncapped offers, two generation resources had uncapped planned uprates plus net CONE times B offer cap for the existing portion of the units, while the remaining 10 generation resources were price takers. Market power mitigation was applied to the Capacity Performance sell offers of zero generation resources, including 0.0 MW.

2021/2022 RPM Base Residual Auction

As shown in Table 5-17, 1,132 generation resources submitted Capacity Performance offers in the 2021/2022 RPM Base Residual Auction. The MMU calculated offer caps for eight generation resources that submitted Capacity Performance offers. Unit-specific ACR-based offer caps were calculated for eight generation resources (0.7 percent) including five generation resources (0.4 percent) with an Avoidable Project Investment Recovery Rate (APIR) and a CPQR component and three generation resources (0.3 percent) with an APIR component and no CPQR component. Of the 1,132 generation resources offered as Capacity Performance, 953 generation resources had the net CONE times B offer cap, zero generation resources had opportunity cost-based offer caps, 11 Planned Generation Capacity Resources had uncapped offers, 31 generation resources had uncapped planned uprates plus net CONE times B offer cap for the existing portion of the units, while the remaining 129 generation resources were price takers. Market power mitigation was applied to the Capacity Performance sell offers of zero generation resources, including 0.0 MW.

MOPR Statistics

Market power mitigation measures are applied to MOPR Screened Generation Resources such that the sell offer is set equal to the MOPR Floor Offer Price when the submitted sell offer is less than the MOPR Floor Offer Price and an exemption or exception was not granted, or the sell offer is set equal to the agreed upon minimum level of sell offer when the sell offer is less than the agreed upon minimum level of sell offer based on a Unit-Specific Exception. As shown in Table 5-21, of the 7,276.0 ICAP MW of MOPR Unit-Specific Exception requests for the 2021/2022 RPM Base Residual Auction, requests for 4,344.0 MW were granted.

Table 5-14 ACR statistics: 2018/2019 RPM Auctions

	2018/2019 Base Residual Auction				2018/2019 First Incremental Auction			
	Base Capacity		Capacity Performance		Base Capacity		Capacity Performance	
Offer Cap/Mitigation Type	Number of Generation Resources	Percent of Generation Resources Offered	Number of Generation Resources	Percent of Generation Resources Offered	Number of Generation Resources	Percent of Generation Resources Offered	Number of Generation Resources	Percent of Generation Resources Offered
Default ACR	164	34.7%	0	0.0%	18	22.5%	0	0.0%
Unit specific ACR (APIR)	45	9.5%	9	0.9%	12	15.0%	8	2.7%
Unit specific ACR (APIR and CPQR)	0	0	26	2.6%	0	0	1	0.3%
Unit specific ACR (non-APIR)	1	0.2%	0	0.0%	0	0.0%	0	0.0%
Unit specific ACR (non-APIR and CPQR)	0	0	0	0.0%	0	0	0	0.0%
Opportunity cost input	7	1.5%	0	0.0%	0	0.0%	0	0.0%
Default ACR and opportunity cost	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Net CONE times B	NA	NA	881	88.8%	NA	NA	261	89.1%
Offer cap of 1.1 times BRA clearing price elected	NA	NA	NA	NA	NA	NA	NA	NA
Uncapped planned uprate and default ACR	2	0.4%	0	0.0%	0	0.0%	0	0.0%
Uncapped planned uprate and opportunity cost	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Uncapped planned uprate and Net CONE times B	NA	NA	6	0.6%	NA	NA	1	0.3%
Uncapped planned uprate and price taker	0	0.0%	1	0.1%	0	0.0%	0	0.0%
Uncapped planned uprate and 1.1 times BRA clearing price elected	NA	NA	NA	NA	NA	NA	NA	NA
Uncapped planned generation resources	8	1.7%	15	1.5%	4	5.0%	7	2.4%
Existing generation resources as price takers	246	52.0%	54	5.4%	46	57.5%	15	5.1%
Total Generation Capacity Resources offered	473	100.0%	992	100.0%	80	100.0%	293	100.0%

	2018/2019 Second Incremental Auction				2018/2019 Third Incremental Auction			
	Base Capacity		Capacity Performance		Base Capacity		Capacity Performance	
Offer Cap/Mitigation Type	Number of Generation Resources	Percent of Generation Resources Offered	Number of Generation Resources	Percent of Generation Resources Offered	Number of Generation Resources	Percent of Generation Resources Offered	Number of Generation Resources	Percent of Generation Resources Offered
Default ACR	12	17.6%	0	0.0%	1	0.5%	0	0.0%
Unit specific ACR (APIR)	11	16.2%	5	1.5%	4	1.9%	3	0.6%
Unit specific ACR (APIR and CPQR)	0	0	0	0.0%	0	0.0%	0	0.0%
Unit specific ACR (non-APIR)	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Unit specific ACR (non-APIR and CPQR)	0	0	0	0.0%	0	0.0%	0	0.0%
Opportunity cost input	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Default ACR and opportunity cost	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Net CONE times B	NA	NA	327	95.1%	NA	NA	364	73.5%
Offer cap of 1.1 times BRA clearing price elected	NA	NA	NA	NA	137	64.9%	98	19.8%
Uncapped planned uprate and default ACR	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Uncapped planned uprate and opportunity cost	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Uncapped planned uprate and Net CONE times B	NA	NA	0	0.0%	NA	NA	0	0.0%
Uncapped planned uprate and price taker	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Uncapped planned uprate and 1.1 times BRA clearing price elected	NA	NA	NA	NA	0	0.0%	0	0.0%
Uncapped planned generation resources	6	8.8%	4	1.2%	5	2.4%	2	0.4%
Existing generation resources as price takers	39	57.4%	8	2.3%	64	30.3%	28	5.7%
Total Generation Capacity Resources offered	68	100.0%	344	100.0%	211	100.0%	495	100.0%

Table 5-15 ACR Statistics: 2019/2020 RPM Auctions

	2019/2020 Base Residual Auction				2019/2020 First Incremental Auction			
	Base Capacity		Capacity Performance		Base Capacity		Capacity Performance	
Offer Cap/Mitigation Type	Number of Generation Resources	Percent of Generation Resources Offered	Number of Generation Resources	Percent of Generation Resources Offered	Number of Generation Resources	Percent of Generation Resources Offered	Number of Generation Resources	Percent of Generation Resources Offered
Default ACR	171	33.9%	0	0.0%	17	21.0%	1	0.3%
Unit specific ACR (APIR)	34	6.7%	8	0.8%	11	13.6%	5	1.3%
Unit specific ACR (APIR and CPQR)	0	0	17	1.7%	0	0	1	0.3%
Unit specific ACR (non-APIR)	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Unit specific ACR (non-APIR and CPQR)	0	0	0	0.0%	0	0	0	0.0%
Opportunity cost input	7	1.4%	0	0.0%	0	0.0%	0	0.0%
Default ACR and opportunity cost	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Net CONE times B	NA	NA	888	88.5%	NA	NA	362	94.8%
Offer cap of 1.1 times BRA clearing price elected	NA	NA	NA	NA	NA	NA	NA	NA
Uncapped planned uprate and default ACR	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Uncapped planned uprate and opportunity cost	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Uncapped planned uprate and Net CONE times B	NA	NA	2	0.2%	NA	NA	0	0.0%
Uncapped planned uprate and price taker	0	0.0%	0	0.0%	0	0.0%	1	0.3%
Uncapped planned uprate and 1.1 times BRA clearing price elected	NA	NA	NA	NA	NA	NA	NA	NA
Uncapped planned generation resources	9	1.8%	14	1.4%	0	0.0%	1	0.3%
Existing generation resources as price takers	284	56.2%	74	7.4%	53	65.4%	11	2.9%
Total Generation Capacity Resources offered	505	100.0%	1,003	100.0%	81	100.0%	382	100.0%

	2019/2020 Second Incremental Auction			
	Base Capacity		Capacity Performance	
Offer Cap/Mitigation Type	Number of Generation Resources	Percent of Generation Resources Offered	Number of Generation Resources	Percent of Generation Resources Offered
Default ACR	10	13.9%	NA	NA
Unit specific ACR (APIR)	8	11.1%	5	1.2%
Unit specific ACR (APIR and CPQR)	0	0	1	0.2%
Unit specific ACR (non-APIR)	0	0.0%	0	0.0%
Unit specific ACR (non-APIR and CPQR)	0	0	0	0.0%
Opportunity cost input	0	0.0%	0	0.0%
Default ACR and opportunity cost	0	0.0%	NA	NA
Net CONE times B	NA	NA	350	85.6%
Offer cap of 1.1 times BRA clearing price elected	NA	NA	NA	NA
Uncapped planned uprate and default ACR	0	0.0%	NA	NA
Uncapped planned uprate and opportunity cost	0	0.0%	0	0.0%
Uncapped planned uprate and Net CONE times B	NA	NA	3	0.7%
Uncapped planned uprate and price taker	1	1.4%	1	0.2%
Uncapped planned uprate and 1.1 times BRA clearing price elected	NA	NA	NA	NA
Uncapped planned generation resources	2	2.8%	0	0.0%
Existing generation resources as price takers	51	70.8%	49	12.0%
Total Generation Capacity Resources offered	72	100.0%	409	100.0%

Table 5-16 ACR Statistics: 2020/2021 RPM Auctions

	2020/2021 Base Residual Auction		2020/2021 First Incremental Auction	
Offer Cap/Mitigation Type	Number of Generation Resources	Percent of Generation Resources Offered	Number of Generation Resources	Percent of Generation Resources Offered
Default ACR	NA	NA	NA	NA
Unit specific ACR (APIR)	3	0.3%	1	0.3%
Unit specific ACR (APIR and CPQR)	11	1.0%	7	1.8%
Unit specific ACR (non-APIR)	0	0.0%	0	0.0%
Unit specific ACR (non-APIR and CPQR)	0	0.0%	0	0.0%
Opportunity cost input	0	0.0%	0	0.0%
Default ACR and opportunity cost	NA	NA	NA	NA
Net CONE times B	956	85.8%	371	93.5%
Offer cap of 1.1 times BRA clearing price elected	NA	NA	NA	NA
Uncapped planned uprate and default ACR	NA	NA	NA	NA
Uncapped planned uprate and opportunity cost	0	0.0%	0	0.0%
Uncapped planned uprate and Net CONE times B	18	1.6%	2	0.5%
Uncapped planned uprate and price taker	2	0.2%	0	0.0%
Uncapped planned uprate and 1.1 times BRA clearing price elected	NA	NA	NA	NA
Uncapped planned generation resources	12	1.1%	6	1.5%
Existing generation resources as price takers	112	10.1%	10	2.5%
Total Generation Capacity Resources offered	1,114	100.0%	397	100.0%

Table 5-17 ACR Statistics: 2021/2022 RPM Auction

	2021/2022 Base Residual Auction	
Offer Cap/Mitigation Type	Number of Generation Resources	Percent of Generation Resources Offered
Default ACR	NA	NA
Unit specific ACR (APIR)	3	0.3%
Unit specific ACR (APIR and CPQR)	5	0.4%
Unit specific ACR (non-APIR)	0	0.0%
Unit specific ACR (non-APIR and CPQR)	0	0.0%
Opportunity cost input	0	0.0%
Default ACR and opportunity cost	NA	NA
Net CONE times B	953	84.2%
Offer cap of 1.1 times BRA clearing price elected	NA	NA
Uncapped planned uprate and default ACR	NA	NA
Uncapped planned uprate and opportunity cost	0	0.0%
Uncapped planned uprate and Net CONE times B	31	2.7%
Uncapped planned uprate and price taker	0	0.0%
Uncapped planned uprate and 1.1 times BRA clearing price elected	NA	NA
Uncapped planned generation resources	11	1.0%
Existing generation resources as price takers	129	11.4%
Total Generation Capacity Resources offered	1,132	100.0%

Table 5-18 APIR Statistics: 2018/2019 RPM Base Residual Auction

	Weighted-Average ($ per MW-day UCAP)	
	Base Capacity	Capacity Performance
Non-APIR units		
ACR	$85.36	$197.45
Net revenues	$117.38	$131.61
Offer caps	$30.74	$65.83
APIR units		
ACR	$406.58	$496.37
Net revenues	$83.43	$139.25
Offer caps	$321.80	$356.54
APIR	$281.13	$344.93
CPQR	$0.00	$10.08
Maximum APIR effect	$1,051.98	$1,051.98

Table 5-19 APIR Statistics: 2019/2020 RPM Base Residual Auction

	Weighted-Average ($ per MW-day UCAP)	
	Base Capacity	Capacity Performance
Non-APIR units		
ACR	$89.05	
Net revenues	$150.86	
Offer caps	$33.97	
APIR units		
ACR	$341.40	$499.18
Net revenues	$65.48	$167.61
Offer caps	$271.22	$323.27
APIR	$230.67	$375.38
CPQR	$0.00	$1.53
Maximum APIR effect	$1,104.93	$1,104.93

Table 5-20 APIR Statistics: 2020/2021 RPM Base Residual Auction

	Weighted-Average ($ per MW-day UCAP)
Non-APIR units	
ACR	
Net revenues	
Offer caps	
APIR units	
ACR	$498.15
Net revenues	$277.52
Offer caps	$209.18
APIR	$235.67
CPQR	$0.23
Maximum APIR effect	$464.71

Table 5-21 MOPR statistics: 2018/2019 through 2021/2022 RPM Base Residual Auctions[95]

		Number of Requests	ICAP (MW)			UCAP (MW)	
		(Company-Plant Level)	Requested	Granted	Offered	Offered	Cleared
2018/2019 Base Residual Auction	Competitive Entry Exemption	28	13,462.5	13,462.5	3,723.3	3,563.6	3,563.6
	Self-Supply Exemption	0	0.0	0.0	0.0	0.0	0.0
	Unit-Specific Exception for resources	0	0.0	0.0	0.0	0.0	0.0
	Unit-Specific Exception for uprates	0	0.0	0.0	0.0	0.0	0.0
	Other MOPR Screened Generation Resources	0	0.0	0.0	543.1	511.5	0.0
	Total	28	13,462.5	13,462.5	4,266.4	4,075.1	3,563.6
2019/2020 Base Residual Auction	Competitive Entry Exemption	28	12,270.0	12,270.0	4,671.0	4,515.1	3,561.7
	Self-Supply Exemption	3	1,827.2	1,827.2	1,779.5	1,697.8	1,697.8
	Unit-Specific Exception for resources	0	0.0	0.0	0.0	0.0	0.0
	Unit-Specific Exception for uprates	0	0.0	0.0	0.0	0.0	0.0
	Other MOPR Screened Generation Resources	0	0.0	0.0	14.4	14.4	0.0
	Total	31	14,097.2	14,097.2	6,464.9	6,227.3	5,259.5
2020/2021 Base Residual Auction	Competitive Entry Exemption	27	12,171.0	12,171.0	3,212.5	3,161.1	2,646.7
	Self-Supply Exemption	0	0.0	0.0	0.0	0.0	0.0
	Unit-Specific Exception for resources	0	0.0	0.0	0.0	0.0	0.0
	Unit-Specific Exception for uprates	0	0.0	0.0	0.0	0.0	0.0
	Other MOPR Screened Generation Resources	0	0.0	0.0	142.0	140.1	0.0
	Total	27	12,171.0	12,171.0	3,354.5	3,301.2	2,646.7
2021/2022 Base Residual Auction	Unit-Specific Exception for resources	8	6,605.0	3,673.0	0.0	0.0	0.0
	Unit-Specific Exception for uprates	15	671.0	671.0	131.3	127.6	127.6
	Other MOPR Screened Generation Resources	0	0.0	0.0	177.5	174.2	0.0
	Total	23	7,276.0	4,344.0	308.8	301.8	127.6

95 There were additional MOPR Screened Generation Resources for which no exceptions or exemptions were requested and to which the MOPR floor was applied. Some numbers not reported as a result of PJM confidentiality rules.

Replacement Capacity[96]

Table 5-22 shows the committed and replacement capacity for all capacity resources for June 1 of each year from 2007 through 2021. The 2019 through 2021 numbers are not final.

Table 5-22 RPM commitments and replacements for all Capacity Resources: June 1, 2007 to June 1, 2021

	UCAP (MW)					
	RPM Cleared	Adjustments to Cleared	Net Replacements	RPM Commitments	RPM Commitment Shortage	RPM Commitments Less Commitment Shortage
01-Jun-07	129,409.2	0.0	0.0	129,409.2	(8.1)	129,401.1
01-Jun-08	130,629.8	0.0	(766.5)	129,863.3	(246.3)	129,617.0
01-Jun-09	134,030.2	0.0	(2,068.2)	131,962.0	(14.7)	131,947.3
01-Jun-10	134,036.2	0.0	(4,179.0)	129,857.2	(8.8)	129,848.4
01-Jun-11	134,182.6	0.0	(6,717.6)	127,465.0	(79.3)	127,385.7
01-Jun-12	141,295.6	(11.7)	(9,400.6)	131,883.3	(157.2)	131,726.1
01-Jun-13	159,844.5	0.0	(12,235.3)	147,609.2	(65.4)	147,543.8
01-Jun-14	161,214.4	(9.4)	(13,615.9)	147,589.1	(1,208.9)	146,380.2
01-Jun-15	173,845.5	(326.1)	(11,849.4)	161,670.0	(1,822.0)	159,848.0
01-Jun-16	179,773.6	(24.6)	(16,157.5)	163,591.5	(924.4)	162,667.1
01-Jun-17	180,590.5	0.0	(13,982.7)	166,607.8	(625.3)	165,982.5
01-Jun-18	175,996.0	0.0	(12,057.8)	163,938.2	(150.5)	163,787.7
01-Jun-19	171,237.2	0.0	(1,083.5)	170,153.7	0.0	170,153.7
01-Jun-20	168,634.0	0.0	(610.1)	168,023.9	0.0	168,023.9
01-Jun-21	163,627.3	0.0	0.0	163,627.3	0.0	163,627.3

Market Performance

Figure 5-7 shows cleared MW weighted average capacity market prices on a Delivery Year basis for the entire history of the PJM capacity markets.

Table 5-23 shows RPM clearing prices for all RPM auctions held through 2018.

Figure 5-8 shows the RPM cleared MW weighted average prices for each LDA for the current delivery year and all results for auctions for future delivery years that have been held through 2018. A summary of these weighted average prices is given in Table 5-24.

Table 5-25 shows RPM revenue by resource type for all RPM auctions held through 2018 with $9.4 billion for new/repower/reactivated generation resources based on the unforced MW cleared and the resource clearing prices. A resource classified as "new/repower/reactivated" is a capacity resource addition since the implementation of RPM and is considered "new/repower/reactivated" for its initial offer and all its subsequent offers in RPM auctions.

Table 5-26 shows RPM revenue by calendar year for all RPM auctions held through 2018. In 2017, RPM revenue was $8.8 billion. In 2018, RPM revenue was $10.3 billion.

Table 5-27 shows the RPM annual charges to load. For the 2017/2018 Delivery Year, RPM annual charges to load are $9.1 billion. For the 2018/2019 Delivery Year, annual charges to load are $11.0 billion.

96 For more details on replacement capacity, see "Analysis of Replacement Capacity for RPM Commitments: June 1, 2007 to June 1, 2017," <http://www.monitoringanalytics.com/reports/Reports/2017/IMM_Report_on_Capacity_Replacement_Activity_4_20171214.pdf> (December 14, 2017).

Table 5-23 Capacity market clearing prices: 2007/2008 through 2021/2022 RPM Auctions

		RPM Clearing Price ($ per MW-day)												
	Product Type	RTO	MAAC	APS	PPL	EMAAC	SWMAAC	DPL South	PSEG	PSEG North	Pepco	ATSI	ComEd	BGE
2007/2008 BRA		$40.80	$40.80	$40.80	$40.80	$197.67	$188.54	$197.67	$197.67	$197.67	$188.54		$40.80	$188.54
2008/2009 BRA		$111.92	$111.92	$111.92	$111.92	$148.80	$210.11	$148.80	$148.80	$148.80	$210.11		$111.92	$210.11
2008/2009 Third Incremental Auction		$10.00	$10.00	$10.00	$10.00	$10.00	$223.85	$10.00	$10.00	$10.00	$223.85		$10.00	$223.85
2009/2010 BRA		$102.04	$191.32	$191.32	$191.32	$191.32	$237.33	$191.32	$191.32	$191.32	$237.33		$102.04	$237.33
2009/2010 Third Incremental Auction		$40.00	$86.00	$86.00	$86.00	$86.00	$86.00	$86.00	$86.00	$86.00	$86.00		$40.00	$86.00
2010/2011 BRA		$174.29	$174.29	$174.29	$174.29	$174.29	$174.29	$186.12	$174.29	$174.29	$174.29		$174.29	$174.29
2010/2011 Third Incremental Auction		$50.00	$50.00	$50.00	$50.00	$50.00	$50.00	$50.00	$50.00	$50.00	$50.00		$50.00	$50.00
2011/2012 BRA		$110.00	$110.00	$110.00	$110.00	$110.00	$110.00	$110.00	$110.00	$110.00	$110.00		$110.00	$110.00
2011/2012 First Incremental Auction		$55.00	$55.00	$55.00	$55.00	$55.00	$55.00	$55.00	$55.00	$55.00	$55.00		$55.00	$55.00
2011/2012 ATSI FRR Integration Auction		$108.89	$108.89	$108.89	$108.89	$108.89	$108.89	$108.89	$108.89	$108.89	$108.89	$108.89	$108.89	$108.89
2011/2012 Third Incremental Auction		$5.00	$5.00	$5.00	$5.00	$5.00	$5.00	$5.00	$5.00	$5.00	$5.00	$5.00	$5.00	$5.00
2012/2013 BRA		$16.46	$133.37	$16.46	$133.37	$139.73	$133.37	$222.30	$139.73	$185.00	$133.37		$16.46	$133.37
2012/2013 ATSI FRR Integration Auction		$20.46	$20.46	$20.46	$20.46	$20.46	$20.46	$20.46	$20.46	$20.46	$20.46	$20.46	$20.46	$20.46
2012/2013 First Incremental Auction		$16.46	$16.46	$16.46	$16.46	$153.67	$16.46	$153.67	$153.67	$153.67	$16.46	$16.46	$16.46	$16.46
2012/2013 Second Incremental Auction		$13.01	$13.01	$13.01	$13.01	$48.91	$13.01	$48.91	$48.91	$48.91	$13.01	$13.01	$13.01	$13.01
2012/2013 Third Incremental Auction		$2.51	$2.51	$2.51	$2.51	$2.51	$2.51	$2.51	$2.51	$2.51	$2.51	$2.51	$2.51	$2.51
2013/2014 BRA		$27.73	$226.15	$27.73	$226.15	$245.00	$226.15	$245.00	$245.00	$245.00	$247.14	$27.73	$27.73	$226.15
2013/2014 First Incremental Auction		$20.00	$20.00	$20.00	$20.00	$178.85	$54.82	$178.85	$178.85	$178.85	$54.82	$20.00	$20.00	$54.82
2013/2014 Second Incremental Auction		$7.01	$10.00	$7.01	$10.00	$40.00	$10.00	$40.00	$40.00	$40.00	$10.00	$7.01	$7.01	$10.00
2013/2014 Third Incremental Auction		$4.05	$30.00	$4.05	$30.00	$188.44	$30.00	$188.44	$188.44	$188.44	$30.00	$4.05	$4.05	$30.00
2014/2015 BRA	Limited	$125.47	$125.47	$125.47	$125.47	$125.47	$125.47	$125.47	$125.47	$213.97	$125.47	$125.47	$125.47	$125.47
2014/2015 BRA	Extended Summer	$125.99	$136.50	$125.99	$136.50	$136.50	$136.50	$136.50	$136.50	$225.00	$136.50	$125.99	$125.99	$136.50
2014/2015 BRA	Annual	$125.99	$136.50	$125.99	$136.50	$136.50	$136.50	$136.50	$136.50	$225.00	$136.50	$125.99	$125.99	$136.50
2014/2015 First Incremental Auction	Limited	$0.03	$5.23	$0.03	$5.23	$5.23	$5.23	$5.23	$5.23	$399.62	$5.23	$0.03	$0.03	$5.23
2014/2015 First Incremental Auction	Extended Summer	$5.54	$16.56	$5.54	$16.56	$16.56	$16.56	$16.56	$16.56	$410.95	$16.56	$5.54	$5.54	$16.56
2014/2015 First Incremental Auction	Annual	$5.54	$16.56	$5.54	$16.56	$16.56	$16.56	$16.56	$16.56	$410.95	$16.56	$5.54	$5.54	$16.56
2014/2015 Second Incremental Auction	Limited	$25.00	$56.94	$25.00	$56.94	$56.94	$56.94	$56.94	$56.94	$310.00	$56.94	$25.00	$25.00	$56.94
2014/2015 Second Incremental Auction	Extended Summer	$25.00	$56.94	$25.00	$56.94	$56.94	$56.94	$56.94	$56.94	$310.00	$56.94	$25.00	$25.00	$56.94
2014/2015 Second Incremental Auction	Annual	$25.00	$56.94	$25.00	$56.94	$56.94	$56.94	$56.94	$56.94	$310.00	$56.94	$25.00	$25.00	$56.94
2014/2015 Third Incremental Auction	Limited	$25.51	$132.20	$25.51	$132.20	$132.20	$132.20	$132.20	$132.20	$256.76	$132.20	$25.51	$25.51	$132.20
2014/2015 Third Incremental Auction	Extended Summer	$25.51	$132.20	$25.51	$132.20	$132.20	$132.20	$132.20	$132.20	$256.76	$132.20	$25.51	$25.51	$132.20
2014/2015 Third Incremental Auction	Annual	$25.51	$132.20	$25.51	$132.20	$132.20	$132.20	$132.20	$132.20	$256.76	$132.20	$25.51	$25.51	$132.20
2015/2016 BRA	Limited	$118.54	$150.00	$118.54	$150.00	$150.00	$150.00	$150.00	$150.00	$150.00	$150.00	$304.62	$118.54	$150.00
2015/2016 BRA	Extended Summer	$136.00	$167.46	$136.00	$167.46	$167.46	$167.46	$167.46	$167.46	$167.46	$167.46	$322.08	$136.00	$167.46
2015/2016 BRA	Annual	$136.00	$167.46	$136.00	$167.46	$167.46	$167.46	$167.46	$167.46	$167.46	$167.46	$357.00	$136.00	$167.46
2015/2016 First Incremental Auction	Limited	$43.00	$111.00	$43.00	$111.00	$111.00	$111.00	$111.00	$122.95	$122.95	$111.00	$168.37	$43.00	$111.00
2015/2016 First Incremental Auction	Extended Summer	$43.00	$111.00	$43.00	$111.00	$111.00	$111.00	$111.00	$122.95	$122.95	$111.00	$168.37	$43.00	$111.00
2015/2016 First Incremental Auction	Annual	$43.00	$111.00	$43.00	$111.00	$111.00	$111.00	$111.00	$122.95	$122.95	$111.00	$168.37	$43.00	$111.00
2015/2016 Second Incremental Auction	Limited	$123.56	$141.12	$123.56	$141.12	$141.12	$141.12	$141.12	$155.02	$155.02	$141.12	$204.10	$123.56	$141.12
2015/2016 Second Incremental Auction	Extended Summer	$136.00	$153.56	$136.00	$153.56	$153.56	$153.56	$153.56	$167.46	$167.46	$153.56	$216.54	$136.00	$153.56
2015/2016 Second Incremental Auction	Annual	$136.00	$153.56	$136.00	$153.56	$153.56	$153.56	$153.56	$167.46	$167.46	$153.56	$216.54	$136.00	$153.56
2015/2016 Third Incremental Auction	Limited	$100.76	$122.33	$100.76	$122.33	$122.33	$122.33	$122.33	$122.56	$122.56	$122.33	$100.76	$100.76	$122.33
2015/2016 Third Incremental Auction	Extended Summer	$163.20	$184.77	$163.20	$184.77	$184.77	$184.77	$184.77	$185.00	$185.00	$184.77	$163.20	$163.20	$184.77
2015/2016 Third Incremental Auction	Annual	$163.20	$184.77	$163.20	$184.77	$184.77	$184.77	$184.77	$185.00	$185.00	$184.77	$163.20	$163.20	$184.77
2016/2017 BRA	Limited	$59.37	$119.13	$59.37	$119.13	$119.13	$119.13	$119.13	$219.00	$219.00	$119.13	$94.45	$59.37	$119.13
2016/2017 BRA	Extended Summer	$59.37	$119.13	$59.37	$119.13	$119.13	$119.13	$119.13	$219.00	$219.00	$119.13	$114.23	$59.37	$119.13
2016/2017 BRA	Annual	$59.37	$119.13	$59.37	$119.13	$119.13	$119.13	$119.13	$219.00	$219.00	$119.13	$114.23	$59.37	$119.13
2016/2017 First Incremental Auction	Limited	$53.93	$89.35	$53.93	$89.35	$89.35	$89.35	$89.35	$214.44	$214.44	$89.35	$94.45	$53.93	$89.35
2016/2017 First Incremental Auction	Extended Summer	$60.00	$119.13	$60.00	$119.13	$119.13	$119.13	$119.13	$244.22	$244.22	$119.13	$100.52	$60.00	$119.13
2016/2017 First Incremental Auction	Annual	$60.00	$119.13	$60.00	$119.13	$119.13	$119.13	$119.13	$244.22	$244.22	$119.13	$100.52	$60.00	$119.13
2016/2017 Second Incremental Auction	Limited	$31.00	$71.00	$31.00	$71.00	$71.00	$71.00	$71.00	$99.01	$212.53	$71.00	$101.50	$31.00	$71.00
2016/2017 Second Incremental Auction	Extended Summer	$31.00	$71.00	$31.00	$71.00	$71.00	$71.00	$71.00	$99.01	$212.53	$71.00	$101.50	$31.00	$71.00
2016/2017 Second Incremental Auction	Annual	$31.00	$71.00	$31.00	$71.00	$71.00	$71.00	$71.00	$99.01	$212.53	$71.00	$101.50	$31.00	$71.00
2016/2017 Capacity Performance Transition Auction	Capacity Performance	$134.00	$134.00	$134.00	$134.00	$134.00	$134.00	$134.00	$134.00	$134.00	$134.00	$134.00	$134.00	$134.00
2016/2017 Third Incremental Auction	Limited	$5.02	$10.02	$5.02	$10.02	$10.02	$10.02	$10.02	$54.76	$184.97	$10.02	$5.02	$5.02	$10.02
2016/2017 Third Incremental Auction	Extended Summer	$5.02	$10.02	$5.02	$10.02	$10.02	$10.02	$10.02	$54.76	$184.97	$10.02	$5.02	$5.02	$10.02
2016/2017 Third Incremental Auction	Annual	$5.02	$10.02	$5.02	$10.02	$10.02	$10.02	$10.02	$54.76	$184.97	$10.02	$5.02	$5.02	$10.02
2017/2018 BRA	Limited	$106.02	$106.02	$106.02	$40.00	$106.02	$106.02	$106.02	$201.02	$201.02	$106.02	$106.02	$106.02	$106.02
2017/2018 BRA	Extended Summer	$120.00	$120.00	$120.00	$53.98	$120.00	$120.00	$120.00	$215.00	$215.00	$120.00	$120.00	$120.00	$120.00
2017/2018 BRA	Annual	$120.00	$120.00	$120.00	$120.00	$120.00	$120.00	$120.00	$215.00	$215.00	$120.00	$120.00	$120.00	$120.00
2017/2018 Capacity Performance Transition Auction	Capacity Performance	$151.50	$151.50	$151.50	$151.50	$151.50	$151.50	$151.50	$151.50	$151.50	$151.50	$151.50	$151.50	$151.50
2017/2018 First Incremental Auction	Limited	$84.00	$84.00	$84.00	$84.00	$84.00	$84.00	$84.00	$143.08	$143.08	$84.00	$84.00	$84.00	$84.00
2017/2018 First Incremental Auction	Extended Summer	$84.00	$84.00	$84.00	$84.00	$84.00	$84.00	$84.00	$143.08	$143.08	$84.00	$84.00	$84.00	$84.00
2017/2018 First Incremental Auction	Annual	$84.00	$84.00	$84.00	$84.00	$84.00	$84.00	$84.00	$143.08	$143.08	$84.00	$84.00	$84.00	$84.00
2017/2018 Second Incremental Auction	Limited	$26.50	$26.50	$26.50	$26.50	$26.50	$26.50	$26.50	$120.43	$179.00	$26.50	$26.50	$26.50	$26.50
2017/2018 Second Incremental Auction	Extended Summer	$26.50	$26.50	$26.50	$26.50	$26.50	$26.50	$26.50	$120.43	$179.00	$26.50	$26.50	$26.50	$26.50
2017/2018 Second Incremental Auction	Annual	$26.50	$26.50	$26.50	$26.50	$26.50	$26.50	$26.50	$120.43	$179.00	$26.50	$26.50	$26.50	$26.50
2017/2018 Third Incremental Auction	Limited	$36.49	$36.49	$36.49	$36.49	$36.49	$36.49	$36.49	$115.76	$115.76	$36.49	$36.49	$36.49	$36.49
2017/2018 Third Incremental Auction	Extended Summer	$36.49	$36.49	$36.49	$36.49	$36.49	$36.49	$36.49	$115.76	$115.76	$36.49	$36.49	$36.49	$36.49
2017/2018 Third Incremental Auction	Annual	$36.49	$36.49	$36.49	$36.49	$36.49	$36.49	$36.49	$115.76	$115.76	$36.49	$36.49	$36.49	$36.49
2018/2019 BRA	Base Capacity	$149.98	$149.98	$149.98	$75.00	$210.63	$149.98	$210.63	$210.63	$210.63	$149.98	$149.98	$200.21	$149.98
2018/2019 BRA	Base Capacity DR/EE	$149.98	$149.98	$149.98	$75.00	$210.63	$59.95	$210.63	$210.63	$210.63	$41.09	$149.98	$200.21	$59.95
2018/2019 BRA	Capacity Performance	$164.77	$164.77	$164.77	$164.77	$225.42	$164.77	$225.42	$225.42	$225.42	$164.77	$164.77	$215.00	$164.77
2018/2019 First Incremental Auction	Base Capacity	$22.51	$22.51	$22.51	$22.51	$80.04	$22.51	$35.68	$80.04	$80.04	$22.51	$22.51	$25.36	$22.51
2018/2019 First Incremental Auction	Base Capacity DR/EE	$22.51	$22.51	$22.51	$22.51	$80.04	$22.51	$35.68	$80.04	$80.04	$22.51	$22.51	$25.36	$22.51
2018/2019 First Incremental Auction	Capacity Performance	$27.15	$27.15	$27.15	$27.15	$84.68	$27.15	$84.68	$84.68	$84.68	$27.15	$27.15	$30.00	$27.15
2018/2019 Second Incremental Auction	Base Capacity	$5.00	$5.00	$5.00	$5.00	$35.02	$5.00	$30.00	$35.02	$35.02	$5.00	$5.00	$5.00	$5.00
2018/2019 Second Incremental Auction	Base Capacity DR/EE	$5.00	$5.00	$5.00	$5.00	$35.02	$5.00	$30.00	$35.02	$35.02	$5.00	$5.00	$5.00	$5.00
2018/2019 Second Incremental Auction	Capacity Performance	$50.00	$50.00	$50.00	$50.00	$80.02	$50.00	$80.02	$80.02	$80.02	$50.00	$50.00	$50.00	$50.00
2018/2019 Third Incremental Auction	Base Capacity	$14.29	$14.29	$14.29	$14.29	$19.30	$14.29	$5.00	$19.30	$19.30	$14.29	$14.29	$14.29	$3.50
2018/2019 Third Incremental Auction	Base Capacity DR/EE	$14.29	$14.29	$14.29	$14.29	$19.30	$14.29	$5.00	$19.30	$19.30	$14.29	$14.29	$14.29	$3.50
2018/2019 Third Incremental Auction	Capacity Performance	$34.99	$34.99	$34.99	$34.99	$34.99	$34.99	$34.99	$34.99	$34.99	$34.99	$34.99	$34.99	$34.99
2019/2020 BRA	Base Capacity	$80.00	$80.00	$80.00	$80.00	$99.77	$80.00	$99.77	$99.77	$99.77	$80.00	$80.00	$182.77	$80.30
2019/2020 BRA	Base Capacity DR/EE	$80.00	$80.00	$80.00	$80.00	$99.77	$80.00	$99.77	$99.77	$99.77	$0.01	$80.00	$182.77	$80.30

Table 5-23 Capacity market clearing prices: 2007/2008 through 2021/2022 RPM Auctions (continued)

		RPM Clearing Price ($ per MW-day)												
	Product Type	RTO	MAAC	APS	PPL	EMAAC	SWMAAC	DPL South	PSEG	PSEG North	Pepco	ATSI	ComEd	BGE
2019/2020 First Incremental Auction	Base Capacity	$15.00	$15.00	$15.00	$15.00	$22.22	$15.00	$22.22	$22.22	$22.22	$15.00	$15.00	$15.00	$15.00
2019/2020 First Incremental Auction	Base Capacity DR/EE	$15.00	$15.00	$15.00	$15.00	$22.22	$15.00	$22.22	$22.22	$22.22	$15.00	$15.00	$15.00	$15.00
2019/2020 First Incremental Auction	Capacity Performance	$51.33	$51.33	$51.33	$51.33	$58.55	$51.33	$58.55	$58.55	$58.55	$51.33	$51.33	$51.33	$51.33
2019/2020 Second Incremental Auction	Base Capacity	$10.01	$10.01	$10.01	$10.01	$10.01	$10.01	$10.01	$10.01	$10.01	$10.01	$10.01	$10.01	$32.14
2019/2020 Second Incremental Auction	Base Capacity DR/EE	$10.01	$10.01	$10.01	$10.01	$10.01	$10.01	$10.01	$10.01	$10.01	$10.01	$10.01	$10.01	$32.14
2019/2020 Second Incremental Auction	Capacity Performance	$32.87	$32.87	$32.87	$32.87	$32.87	$32.87	$32.87	$32.87	$32.87	$32.87	$32.87	$32.87	$55.00
2020/2021 BRA	Capacity Performance	$76.53	$86.04	$76.53	$86.04	$187.87	$86.04	$187.87	$187.87	$187.87	$86.04	$76.53	$188.12	$86.04
2020/2021 First Incremental Auction	Capacity Performance	$42.90	$42.90	$42.90	$42.90	$42.90	$42.90	$42.90	$42.90	$42.90	$42.90	$42.90	$42.90	$42.90
2021/2022 BRA	Capacity Performance	$140.00	$140.00	$140.00	$140.00	$165.73	$140.00	$165.73	$204.29	$204.29	$140.00	$171.33	$195.55	$200.30

Table 5-24 Weighted average clearing prices by zone: 2018/2019 through 2021/2022

	Weighted Average Clearing Price ($ per MW-day)			
LDA	2018/2019	2019/2020	2020/2021	2021/2022
RTO				
AEP	$158.20	$95.57	$75.83	$140.05
APS	$158.20	$95.57	$75.83	$140.05
ATSI	$148.42	$94.74	$74.98	$171.32
Cleveland	$158.68	$95.36	$72.16	$171.33
ComEd	$199.02	$194.82	$184.32	$195.55
DAY	$158.20	$95.57	$75.83	$140.05
DEOK	$158.20	$95.57	$75.83	$140.05
DLCO	$158.20	$95.57	$75.83	$140.05
Dominion	$158.20	$95.57	$75.83	$140.05
EKPC	$158.20	$95.57	$75.83	$140.05
MAAC				
EMAAC				
AECO	$214.31	$113.49	$186.61	$165.68
DPL	$214.31	$113.49	$186.61	$165.68
DPL South	$211.38	$116.08	$184.53	$165.73
JCPL	$214.31	$113.49	$186.61	$165.68
PECO	$214.31	$113.49	$186.61	$165.68
PSEG	$210.92	$116.35	$187.39	$204.20
PSEG North	$211.71	$116.64	$186.33	$204.27
RECO	$214.31	$113.49	$186.61	$165.68
SWMAAC				
BGE	$141.58	$93.53	$85.24	$199.00
Pepco	$144.90	$91.46	$85.54	$140.00
WMAAC				
Met-Ed	$152.65	$96.38	$85.16	$140.00
PENELEC	$152.65	$96.38	$85.16	$140.00
PPL	$147.90	$95.36	$85.70	$140.08

Table 5-25 RPM revenue by type: 2007/2008 through 2021/2022[97] [98]

				Coal		Gas		Hydroelectric	
	Demand Resources	Energy Efficiency Resources	Imports	Existing	New/repower/ reactivated	Existing	New/repower/ reactivated	Existing	New/repower/ reactivated
2007/2008	$5,537,085	$0	$22,225,980	$1,019,060,206	$0	$1,625,158,046	$3,516,075	$209,490,444	$0
2008/2009	$35,349,116	$0	$60,918,903	$1,835,059,769	$0	$2,115,862,522	$9,784,064	$287,838,147	$12,255
2009/2010	$65,762,003	$0	$56,517,793	$2,409,315,953	$1,854,781	$2,551,967,501	$30,168,831	$364,731,344	$11,173
2010/2011	$60,235,796	$0	$106,046,871	$2,648,278,766	$3,168,069	$2,829,039,737	$58,065,964	$442,410,730	$19,085
2011/2012	$55,795,785	$139,812	$185,421,273	$1,586,775,249	$28,330,047	$1,721,272,563	$98,448,693	$278,529,660	$0
2012/2013	$264,387,897	$11,408,552	$13,260,822	$1,014,858,378	$7,568,127	$1,256,600,367	$76,633,409	$179,117,374	$11,998
2013/2014	$558,715,114	$21,598,174	$31,804,645	$1,741,613,525	$12,950,135	$2,154,401,813	$167,844,235	$308,853,673	$25,708
2014/2015	$681,315,139	$42,308,549	$135,573,409	$1,935,468,356	$57,078,818	$2,176,442,220	$205,555,569	$333,941,614	$6,649,774
2015/2016	$903,496,003	$66,652,986	$260,806,674	$2,902,870,267	$63,682,708	$2,676,692,075	$535,039,154	$389,540,948	$15,478,144
2016/2017	$466,952,356	$68,709,670	$244,091,507	$2,137,545,515	$72,217,195	$2,217,027,225	$667,098,133	$283,613,426	$13,927,638
2017/2018	$515,145,457	$86,147,605	$218,710,769	$2,452,687,763	$62,790,145	$2,550,970,172	$984,733,791	$348,972,234	$15,219,121
2018/2019	$637,742,320	$103,105,796	$263,475,004	$2,637,322,434	$77,072,397	$2,992,482,882	$1,444,760,231	$416,075,805	$15,382,098
2019/2020	$372,756,931	$89,249,885	$83,736,046	$1,655,571,636	$47,528,002	$1,949,596,494	$1,058,669,656	$247,843,671	$6,208,824
2020/2021	$343,544,146	$93,092,140	$74,256,199	$1,318,324,680	$36,115,158	$2,080,256,094	$1,146,062,527	$209,060,912	$7,737,607
2021/2022	$631,409,762	$166,627,498	$130,197,690	$2,079,667,778	$66,256,260	$2,670,256,030	$1,676,705,702	$295,309,520	$11,589,480

	Nuclear		Oil		Solar		Solid waste	
	Existing	New/repower/ reactivated	Existing	New/repower/ reactivated	Existing	New/repower/ reactivated	Existing	New/repower/ reactivated
2007/2008	$996,085,233	$0	$339,272,020	$0	$0	$0	$31,512,230	$0
2008/2009	$1,322,601,837	$0	$375,774,257	$4,837,523	$0	$0	$35,011,991	$0
2009/2010	$1,517,723,628	$0	$447,358,085	$5,676,582	$0	$0	$42,758,762	$523,739
2010/2011	$1,799,258,125	$0	$440,593,115	$4,339,539	$0	$0	$40,731,606	$413,503
2011/2012	$1,079,386,338	$0	$263,061,402	$967,887	$0	$66,978	$25,636,836	$261,690
2012/2013	$762,719,550	$0	$248,107,065	$2,772,987	$0	$1,246,337	$26,840,670	$316,420
2013/2014	$1,346,223,419	$0	$385,720,626	$5,670,399	$0	$3,523,555	$43,943,130	$1,977,705
2014/2015	$1,464,950,862	$0	$319,758,617	$4,106,697	$0	$3,836,582	$34,281,137	$1,709,533
2015/2016	$1,850,033,226	$0	$397,556,965	$5,947,275	$0	$7,064,983	$35,862,368	$6,179,607
2016/2017	$1,483,759,630	$0	$261,495,016	$4,030,823	$0	$7,057,256	$32,648,789	$6,380,604
2017/2018	$1,694,447,711	$0	$276,148,715	$3,888,126	$0	$10,899,883	$34,771,100	$9,036,976
2018/2019	$2,004,607,689	$0	$339,771,633	$2,922,855	$0	$16,928,323	$38,243,467	$9,658,138
2019/2020	$1,275,670,828	$0	$185,300,298	$1,723,692	$0	$11,954,557	$21,205,162	$5,326,702
2020/2021	$1,421,992,631	$0	$212,589,855	$1,408,492	$0	$7,389,376	$26,917,827	$5,428,707
2021/2022	$1,181,920,902	$0	$253,987,440	$2,401,396	$0	$29,673,108	$31,924,862	$7,757,690

	Wind		
	Existing	New/repower/ reactivated	Total revenue
2007/2008	$430,065	$0	$4,252,287,381
2008/2009	$1,180,153	$2,917,048	$6,087,147,586
2009/2010	$2,011,156	$6,836,827	$7,503,218,157
2010/2011	$1,819,413	$15,232,177	$8,449,652,496
2011/2012	$1,072,929	$9,919,881	$5,335,087,023
2012/2013	$812,644	$5,052,036	$3,871,714,635
2013/2014	$1,373,205	$13,538,988	$6,799,778,047
2014/2015	$1,524,551	$32,766,219	$7,437,267,646
2015/2016	$1,829,269	$42,994,253	$10,161,726,902
2016/2017	$1,144,873	$26,189,042	$7,993,888,695
2017/2018	$1,529,251	$40,577,901	$9,306,676,719
2018/2019	$1,166,553	$54,226,228	$11,054,943,851
2019/2020	$756,891	$45,598,006	$7,058,697,281
2020/2021	$25,124	$35,671,349	$7,019,872,821
2021/2022	$2,089,282	$63,102,701	$9,300,877,101

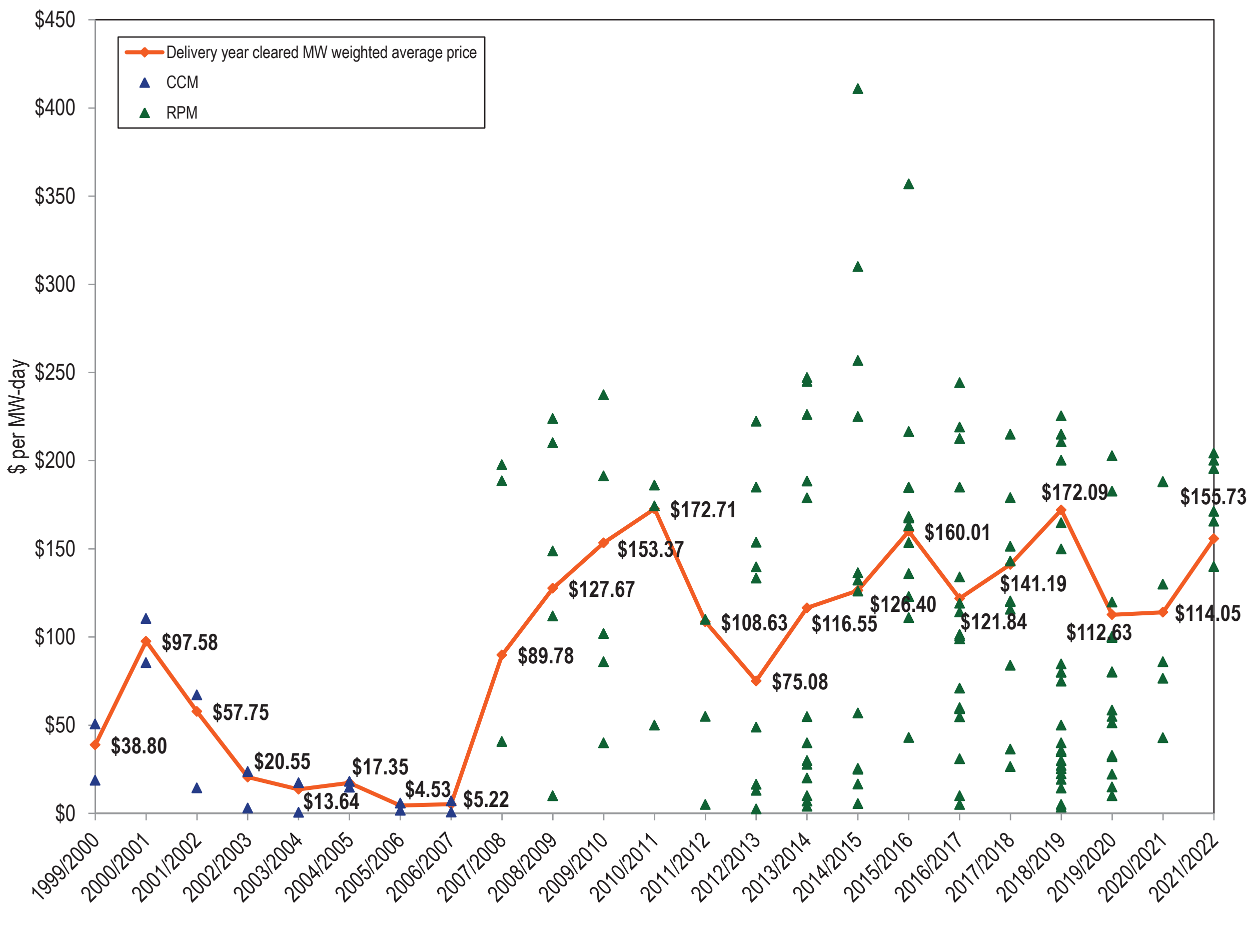
97 A resource classified as "new/repower/reactivated" is a capacity resource addition since the implementation of RPM and is considered "new/repower/reactivated" for its initial offer and all its subsequent offers in RPM Auctions.

98 The results for the ATSI Integration Auctions are not included in this table.

Table 5-26 RPM revenue by calendar year: 2007 through 2022[99]

Year	Weighted Average RPM Price ($ per MW-day)	Weighted Average Cleared UCAP (MW)	Effective Days	RPM Revenue
2007	$89.78	129,409.2	214	$2,486,310,108
2008	$111.93	130,223.2	366	$5,334,880,241
2009	$142.74	132,772.0	365	$6,917,391,702
2010	$164.71	134,033.9	365	$8,058,113,907
2011	$135.14	134,105.2	365	$6,615,032,130
2012	$89.01	137,684.7	366	$4,485,656,150
2013	$99.39	154,044.3	365	$5,588,442,225
2014	$122.32	160,668.7	365	$7,173,539,072
2015	$146.10	169,112.0	365	$9,018,343,604
2016	$137.69	176,742.6	366	$8,906,998,628
2017	$133.19	180,272.0	365	$8,763,578,112
2018	$159.31	177,680.6	365	$10,331,688,133
2019	$137.23	173,706.1	365	$8,700,631,571
2020	$113.46	169,707.2	366	$7,047,241,889
2021	$138.49	165,333.1	365	$8,357,228,755
2022	$155.73	163,627.3	151	$3,847,760,116

Figure 5-7 History of capacity prices: 1999/2000 through 2021/2022[100]



99 The results for the ATSI Integration Auctions are not included in this table.

100 The 1999/2000 through 2006/2007 capacity prices are CCM combined market, weighted average prices. The 2007/2008 through 2021/2022 capacity prices are RPM weighted average prices. The CCM data points plotted are cleared MW weighted average prices for the daily and monthly markets by delivery year. The RPM data points plotted are RPM resource clearing prices. For the 2014/2015 and subsequent delivery years, only the prices for Annual Resources or Capacity Performance Resources are plotted.

Figure 5-8 Map of RPM capacity prices: 2018/2019 through 2021/2022

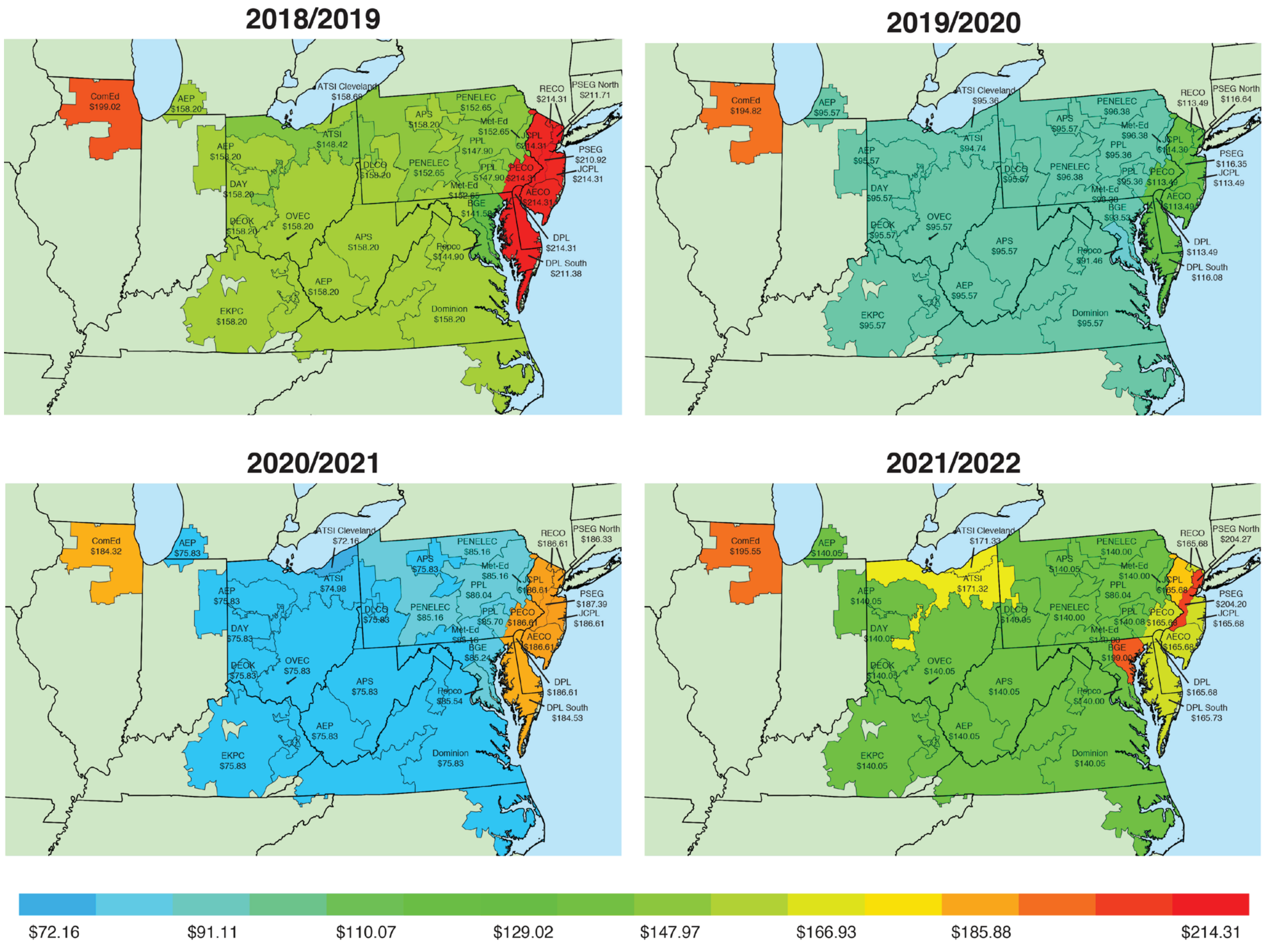


Table 5-27 RPM cost to load: 2017/2018 through 2021/2022 RPM Auctions[101 102 103]

	Net Load Price ($ per MW-day)	UCAP Obligation (MW)	Annual Charges
2017/2018			
Rest of RTO	$153.61	94,874.5	$5,319,445,392
Rest of MAAC	$153.74	44,352.0	$2,488,734,815
PSEG	$208.59	10,932.0	$832,333,767
PPL	$151.86	7,935.5	$439,869,055
Total		158,094.0	$9,080,383,029
2018/2019			
Rest of RTO	$164.70	80,837.7	$4,859,734,465
Rest of MAAC	$218.98	31,118.9	$2,487,249,930
BGE	$158.20	7,701.4	$444,710,759
DPL	$219.29	4,463.7	$357,277,053
ComEd	$212.03	24,752.4	$1,915,591,298
Pepco	$156.90	7,329.2	$419,746,111
PPL	$155.11	8,300.9	$469,969,694
Total		164,504.2	$10,954,279,310
2019/2020			
Rest of RTO	$98.01	89,481.5	$3,209,816,762
Rest of EMAAC	$115.68	24,189.5	$1,024,134,241
BGE	$97.72	7,609.2	$272,145,810
ComEd	$191.70	25,196.6	$1,767,877,460
Pepco	$92.80	7,281.3	$247,297,867
PSEG	$115.93	11,169.9	$473,945,328
Total		164,928.0	$6,995,217,469
2020/2021			
Rest of RTO	$77.00	69,538.0	$1,954,438,669
Rest of MAAC	$86.89	29,572.5	$937,886,000
Rest of EMAAC	$176.17	34,949.0	$2,247,251,699
ComEd	$183.79	25,040.0	$1,679,743,111
DEOK	$103.53	5,208.1	$196,815,744
Total		164,307.7	$7,016,135,223
2021/2022			
Rest of RTO	$140.53	82,080.4	$4,210,274,861
Rest of EMAAC	$163.08	23,762.8	$1,414,495,718
ATSI	$157.99	14,464.9	$834,165,114
BGE	$161.62	7,435.0	$438,596,021
ComEd	$192.69	24,983.0	$1,757,064,009
PSEG	$184.03	10,901.1	$732,248,951
Total		163,627.3	$9,386,844,675

101 The RPM annual charges are calculated using the rounded, net load prices as posted in the PJM RPM Auction results.

102 There is no separate obligation for DPL South as the DPL South LDA is completely contained within the DPL Zone. There is no separate obligation for PSEG North as the PSEG North LDA is completely contained within the PSEG Zone.

103 Prior to the 2009/2010 Delivery Year, the final UCAP obligation is determined after the clearing of the Second Incremental Auction. For the 2009/2010 through 2011/2012 Delivery Years, the final UCAP obligations are determined after the clearing of the Third Incremental Auction. Effective with the 2012/2013 Delivery Year, the final UCAP obligation is determined after the clearing of the final Incremental Auction. Prior to the 2012/2013 Delivery Year, the Final Zonal Capacity Prices are determined after certification of ILR. Effective with the 2012/2013 Delivery Year, the Final Zonal Capacity Prices are determined after the final Incremental Auction. The 2019/2020, 2020/2021, and 2021/2022 Net Load Prices are not finalized. The 2019/2020, 2020/2021, and 2021/2022 obligation MW are not finalized.

Reliability Must Run (RMR) Service

PJM must make out of market payments to units for Reliability Must Run (RMR) service during periods when a unit that would otherwise have been deactivated is needed for reliability.[104] The need for RMR service reflects a flawed market design and/or planning process problems. If a unit is needed for reliability, the market should reflect a locational value consistent with that need which would result in the unit remaining in service or being replaced by a competitor unit. The planning process should evaluate the impact of the loss of units at risk and determine in advance whether transmission upgrades are required.[105]

When notified of an intended deactivation, the Market Monitor performs a market power study to ensure that the deactivation is economic, not an exercise of market power through withholding, and consistent with competition.[106] PJM performs a system study to determine whether the system can accommodate the deactivation on the desired date, and if not, when it could.[107] If PJM determines that it needs a unit for a period beyond the intended deactivation date, PJM will request a unit to provide RMR service.[108] The PJM market rules do not require an owner to provide RMR service, but owners must provide 90 days advance notice of a proposed deactivation.[109] The owner of a generation capacity resource must provide notice of a proposed deactivation in order to avoid a requirement to offer in RPM auctions.[110] In order to avoid submitting an offer for a unit in the next three-year forward RPM base residual auction, an owner must show "a documented plan in place to retire the resource," including a notice of deactivation filed with PJM, 120 days prior to such auction.[111]

104 OATT Part V.

105 *See, e.g.*, 140 FERC ¶ 61,237 at P 36 (2012) ("The evaluation of alternatives to an SSR designation is an important step that deserves the full consideration of MISO and its stakeholders to ensure that SSR Agreements are used only as a 'limited, last-resort measure.'"); 118 FERC ¶ 61,243 at P 41 (2007) ("the market participants that pay for the agreements pay out-of-market prices for the service provided under the RMR agreements, which broadly hinders market development and performance.[footnote omitted] As a result of these factors, we have concluded that RMR agreements should be used as a last resort."); 110 FERC ¶ 61,315 at P 40 (2005) ("The Commission has stated on several occasions that it shares the concerns . . . that RMR agreements not proliferate as an alternative pricing option for generators, and that they are used strictly as a last resort so that units needed for reliability receive reasonable compensation.").

106 OATT § 113.2; OATT Attachment M § IV.1.

107 OATT § 113.2.

108 *Id.*

109 OATT § 113.1.

110 OATT Attachment DD § 6.6(g).

111 *Id.*

Under the current rules, a unit providing RMR service can recover its costs under either the deactivation avoidable cost rate (DACR), which is a formula rate, or the cost of service recovery rate. The deactivation avoidable cost rate is designed to permit the recovery of the costs of the unit's "continued operation," termed "avoidable costs," plus an incentive adder.[112] Avoidable costs are defined to mean "incremental expenses directly required for the operation of a generating unit." [113] The incentives escalate for each year of service (first year, 10 percent; second year, 20 percent; third year, 35 percent; fourth year, 50 percent).[114] The rules provide terms for early termination of RMR service and for the repayment of project investment by owners of units that choose to keep units in service after the RMR period ends.[115] Project investment is capped at $2 million, above which FERC approval is required.[116] The cost of service rate is designed to permit the recovery of the unit's "cost of service rate to recover the entire cost of operating the generating unit" if the generation owner files a separate rate schedule at FERC. [117]

Table 5-28 shows units that have provided or are providing RMR service to PJM.

In each of the cost of service recovery rate filings for RMR service, the scope of recovery permitted under the cost of service approach defined in Section 119 has been a significant issue. Owners have sought to recover fixed costs, incurred prior to the noticed deactivation date, in addition to the cost of operating the generating unit. Owners have cited the cost of service reference to mean that the unit is entitled to file to recover costs that it was unable to recover in the competitive markets, in addition to recovery of costs of actually providing the RMR service.

The cost of service recovery rate approach has been interpreted by the companies using that approach to allow the company to establish a rate base including investment in the existing plant and new investment necessary to provide RMR service and to earn a return on that rate base and receive depreciation of that rate base. Companies developing the cost of service recovery rate have ignored the tariff's limitation to the costs of operating the unit during the RMR service period and have included costs incurred prior to the decision to the deactivate.[118] In one cost of service recovery rate, the filing included costs that already had been written off on the company's public books.[119] Unit owners have filed for revenues under the cost of service method that substantially exceed the actual incremental costs of providing RMR service.

Table 5-28 RMR service summary

Unit Names	Owner	ICAP (MW)	Cost Recovery Method	Docket Numbers	Start of Term	End of Term
B.L. England 2	RC Cape May Holdings, LLC	150.0	Cost of Service Recovery Rate	ER17-1083	01-May-17	31-May-19
Yorktown 1	Dominion Virginia Power	159.0	Deactivation Avoidable Cost Rate	ER17-750	06-Jan-17	08-Mar-19
Yorktown 2	Dominion Virginia Power	164.0	Deactivation Avoidable Cost Rate	ER17-750	06-Jan-17	08-Mar-19
B.L. England 3	RC Cape May Holdings, LLC	148.0	Cost of Service Recovery Rate	ER17-1083	01-May-17	24-Jan-18
Ashtabula	FirstEnergy Service Company	210.0	Deactivation Avoidable Cost Rate	ER12-2710	01-Sep-12	11-Apr-15
Eastlake 1	FirstEnergy Service Company	109.0	Deactivation Avoidable Cost Rate	ER12-2710	01-Sep-12	15-Sep-14
Eastlake 2	FirstEnergy Service Company	109.0	Deactivation Avoidable Cost Rate	ER12-2710	01-Sep-12	15-Sep-14
Eastlake 3	FirstEnergy Service Company	109.0	Deactivation Avoidable Cost Rate	ER12-2710	01-Sep-12	15-Sep-14
Lakeshore	FirstEnergy Service Company	190.0	Deactivation Avoidable Cost Rate	ER12-2710	01-Sep-12	15-Sep-14
Elrama 4	GenOn Power Midwest, LP	171.0	Cost of Service Recovery Rate	ER12-1901	01-Jun-12	01-Oct-12
Niles 1	GenOn Power Midwest, LP	109.0	Cost of Service Recovery Rate	ER12-1901	01-Jun-12	01-Oct-12
Cromby 2 and Diesel	Exelon Generation Company, LLC	203.7	Cost of Service Recovery Rate	ER10-1418	01-Jun-11	01-Jan-12
Eddystone 2	Exelon Generation Company, LLC	309.0	Cost of Service Recovery Rate	ER10-1418	01-Jun-11	01-Jun-12
Brunot Island CT2A, CT2B, CT3 and CC4	Orion Power MidWest, L.P.	244.0	Cost of Service Recovery Rate	ER06-993	16-May-06	05-Jul-07
Hudson 1	PSEG Energy Resources & Trade LLC and PSEG Fossil LLC	355.0	Cost of Service Recovery Rate	ER05-644, ER11-2688	25-Feb-05	08-Dec-11
Sewaren 1-4	PSEG Energy Resources & Trade LLC and PSEG Fossil LLC	453.0	Cost of Service Recovery Rate	ER05-644	25-Feb-05	01-Sep-08

Only two of seven owners have used the deactivation avoidable cost rate approach. The other five owners used the cost of service recovery rate, despite the greater administrative expense.

Because an RMR unit is needed by PJM for reliability reasons, and the provision of RMR service is voluntary

112 OATT § 114 (Deactivation Avoidable Credit = ((Deactivation Avoidable Cost Rate + Applicable Adder) * MW capability of the unit * Number of days in the month) – Actual Net Revenues).
113 OATT § 115.
114 *Id.*
115 OATT § 118.
116 OATT §§ 115, 117.
117 OATT § 119.
118 See, e.g., FERC Dockets Nos. ER10-1418-000, ER12-1901-000.
119 See GenOn Filing, Docket No. ER12-1901-000 (May 31, 2012) at Exh. No. GPM-1 at 9:16–21.

in PJM, owners of RMR service have significant market power in establishing the terms of RMR service.

RMR service should be provided to PJM customers at reasonable rates, which reflect the riskless nature of providing such service to owners, the reliability need for such service and the opportunity for owners to be guaranteed recovery of 100 percent of the actual costs incurred to provide the service plus an incentive markup.

The cost of service recovery rates have been excessive compared to the actual costs of providing RMR service. The DACR method also provides excessive incentives for service longer than a year, given that customers bear the risks.

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, based in part on its experience with application of the deactivation avoidable cost rate and proceedings filed under Section 119, the following improvements to the DACR provisions:

- Revise the applicable adders in Section 114 to be 15 percent for the second year of RMR service and 20 percent for the provision of RMR service in excess of two years.
- Add true up provisions that ensure that the RMR service provider is reimbursed for, and consumers pay for, the actual costs associated with the RMR service, plus the applicable adder.
- Eliminate the $2 million cap on project investment expenditures.
- Clearly distinguish operating expenses and project investment costs.
- Clarify the tariff language in Section 118 regarding the refund of project investment in the event the RMR unit continues operation beyond the RMR term.

Generator Performance

Generator performance results from the interaction between the physical characteristics of the units and the level of expenditures made to maintain the capability of the units, which in turn is a function of incentives from energy, ancillary services and capacity markets. Generator performance indices include those based on total hours in a period (generator performance factors) and those based on hours when units are needed to operate by the system operator (generator forced outage rates).

Capacity Factor

Capacity factor measures the actual output of a power plant over a period of time compared to the potential output of the unit had it been running at full nameplate capacity for every hour during that period. Table 5-29 shows the capacity factors by unit type for 2017 and 2018. In 2018, nuclear units had a capacity factor of 94.2 percent, compared to 94.1 percent in 2017; combined cycle units had a capacity factor of 60.0 percent in 2018, compared to a capacity factor of 58.4 percent in 2017; all steam units had a capacity factor of 39.0 percent in 2018, compared to 40.8 percent in 2017; coal units had a capacity factor of 44.4 percent in 2018, compared to 46.6 percent in 2017.

Table 5-29 Capacity factor (By unit type (GWh)): 2017 and 2018[120 121]

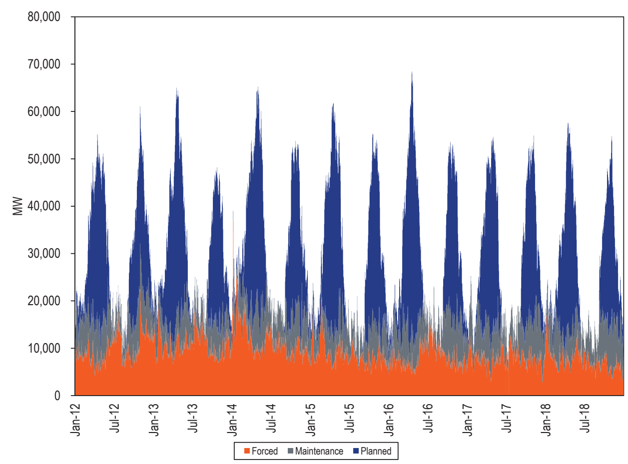
	2017		2018		Change in
Unit Type	Generation (GWh)	Capacity Factor	Generation (GWh)	Capacity Factor	2018 from 2017
Battery	25.1	0.9%	14.3	0.6%	(0.3%)
Combined Cycle	195,631.7	58.4%	234,614.7	60.0%	1.5%
Single Fuel	159,214.6	62.6%	194,921.2	63.5%	0.9%
Dual Fuel	36,417.1	45.1%	39,693.5	47.1%	2.0%
Combustion Turbine	13,384.9	5.3%	17,590.9	6.9%	1.7%
Single Fuel	9,708.0	5.1%	11,810.7	6.3%	1.2%
Dual Fuel	3,676.8	5.7%	5,780.2	8.7%	3.0%
Diesel	322.3	10.1%	351.8	10.4%	0.3%
Single Fuel	314.3	11.1%	341.9	11.4%	0.2%
Dual Fuel	8.1	2.2%	9.9	2.7%	0.5%
Diesel (Landfill gas)	1,727.7	51.6%	1,712.8	51.8%	0.2%
Fuel Cell	226.7	86.2%	225.9	82.9%	(3.4%)
Nuclear	287,575.8	94.1%	286,155.4	94.2%	0.0%
Pumped Storage Hydro	6,475.4	14.6%	7,004.9	15.8%	1.2%
Run of River Hydro	8,393.0	32.0%	12,410.6	46.8%	14.8%
Solar	1,463.1	17.0%	2,104.9	17.7%	0.7%
Steam	272,282.7	40.8%	253,826.7	39.0%	(1.8%)
Biomass	5,859.6	59.3%	6,451.9	68.6%	9.2%
Coal	258,498.3	46.6%	241,022.0	44.4%	(2.2%)
Single Fuel	252,866.1	48.6%	235,262.5	45.8%	(2.8%)
Dual Fuel	5,632.2	16.6%	5,759.5	19.6%	3.0%
Natural Gas	7,770.2	9.3%	5,987.5	7.5%	(1.8%)
Single Fuel	678.6	7.1%	637.8	8.0%	0.9%
Dual Fuel	7,091.6	9.6%	5,349.7	7.4%	(2.1%)
Oil	154.6	0.8%	365.2	1.9%	1.2%
Wind	20,714.1	29.5%	21,626.8	28.4%	(1.1%)
Total	808,228.0	47.0%	837,644.2	47.4%	0.4%

Generator Performance Factors

Generator outages fall into three categories: planned, maintenance, and forced. The MW on outage vary throughout the year. For example, the MW on planned outage are generally highest in the spring and fall, as shown in Figure 5-9, due to restrictions on planned outages during the winter and summer. The effect of the seasonal variation in outages can be seen in the monthly generator performance metrics in Figure 5-12.

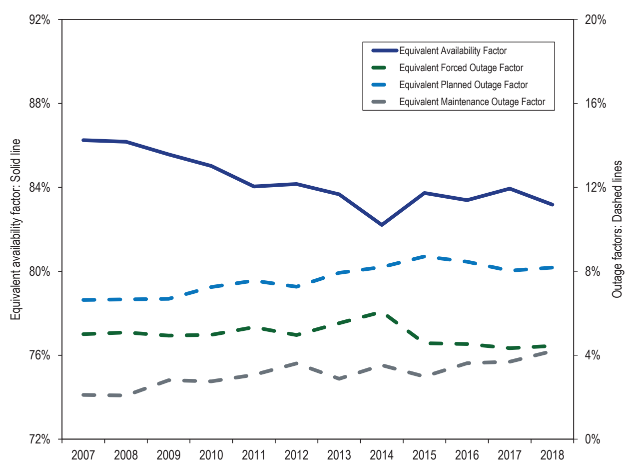
Performance factors include the equivalent availability factor (EAF), the equivalent maintenance outage factor (EMOF), the equivalent planned outage factor (EPOF) and the equivalent forced outage factor (EFOF). These four factors add to 100 percent for any generating unit. The EAF is the proportion of hours in a year when a unit is available to generate at full capacity while the three outage factors include all the hours when a unit is unavailable. The EMOF is the proportion of hours in a year when a unit is unavailable because of maintenance outages and maintenance deratings. The EPOF is the proportion of hours in a year when a unit is unavailable because of planned outages and planned deratings. The EFOF is the proportion of hours in a year when a unit is unavailable because of forced outages and forced deratings.

Figure 5-9 Outages (MW): 2012 through 2018



The PJM aggregate EAF, EFOF, EPOF, and EMOF are shown in Figure 5-10. Metrics by unit type are shown in Table 5-30.

Figure 5-10 Equivalent outage and availability factors: 2007 to 2018



120 The capacity factors in this table are based on nameplate capacity values, and are calculated based on when the units come on line.

121 The subcategories of steam units are consolidated consistent with confidentiality rules. Coal is comprised of coal and waste coal. Natural gas is comprised of natural gas and propane. Oil is comprised of both heavy and light oil. Biomass is comprised of biomass, landfill gas, and municipal solid waste.

Table 5-30 EFOF, EPOF, EMOF and EAF by unit type: 2007 through 2018

	Coal				Combined Cycle				Combustion Turbine				Diesel			
	EFOF	EPOF	EMOF	EAF	EFOF	EPOF	EMOF	EAF	EFOF	EPOF	EMOF	EAF	EFOF	EPOF	EMOF	EAF
2007	7.7%	8.7%	2.8%	80.8%	2.4%	6.1%	1.8%	89.7%	4.7%	2.5%	2.7%	90.1%	10.2%	0.6%	1.6%	87.6%
2008	7.8%	7.5%	2.5%	82.2%	2.2%	6.0%	1.7%	90.1%	2.8%	4.1%	2.3%	90.7%	9.1%	1.0%	1.2%	88.7%
2009	6.8%	8.7%	3.6%	81.0%	2.7%	5.8%	3.2%	88.3%	1.5%	2.8%	2.5%	93.3%	6.6%	0.6%	1.1%	91.7%
2010	7.8%	8.9%	4.1%	79.2%	2.1%	7.9%	2.7%	87.3%	2.0%	2.8%	2.1%	93.1%	4.4%	0.4%	1.5%	93.6%
2011	8.3%	8.4%	4.5%	78.9%	2.3%	8.4%	2.1%	87.2%	2.1%	3.7%	2.4%	91.8%	3.3%	0.1%	1.8%	94.8%
2012	7.3%	8.5%	5.8%	78.4%	3.8%	8.2%	2.1%	86.0%	2.9%	3.1%	1.8%	92.2%	3.9%	0.7%	2.4%	93.1%
2013	8.6%	9.9%	4.5%	77.1%	2.5%	8.3%	2.2%	87.0%	5.2%	4.0%	1.8%	89.1%	6.0%	0.3%	1.4%	92.4%
2014	9.4%	9.1%	5.5%	76.0%	2.7%	9.4%	2.5%	85.4%	6.3%	4.0%	1.9%	87.9%	13.8%	0.4%	2.2%	83.5%
2015	7.7%	9.5%	4.5%	78.3%	2.2%	10.5%	2.0%	85.3%	2.9%	4.2%	2.5%	90.4%	7.6%	0.3%	2.7%	89.4%
2016	8.4%	8.7%	6.3%	76.6%	2.9%	10.9%	1.8%	84.4%	2.2%	5.3%	2.7%	89.8%	5.2%	0.2%	2.6%	92.0%
2017	9.5%	9.7%	6.9%	73.9%	1.9%	10.8%	1.6%	85.7%	1.4%	5.8%	2.0%	90.8%	6.5%	0.3%	2.0%	91.1%
2018	9.6%	10.9%	8.1%	71.4%	1.6%	9.4%	1.5%	87.6%	2.0%	5.5%	1.8%	90.8%	6.6%	0.9%	3.3%	89.2%

	Hydroelectric				Nuclear				Other			
	EFOF	EPOF	EMOF	EAF	EFOF	EPOF	EMOF	EAF	EFOF	EPOF	EMOF	EAF
2007	1.3%	7.2%	1.4%	90.1%	1.3%	5.3%	0.3%	93.1%	6.1%	7.6%	3.0%	83.3%
2008	1.3%	7.8%	2.1%	88.8%	1.8%	5.1%	0.8%	92.3%	8.6%	10.3%	3.1%	78.0%
2009	2.3%	8.7%	2.3%	86.8%	4.1%	5.2%	0.6%	90.1%	7.7%	7.6%	4.6%	80.0%
2010	0.7%	8.6%	1.9%	88.8%	2.3%	5.4%	0.5%	91.8%	8.1%	9.8%	3.5%	78.6%
2011	1.7%	11.7%	1.9%	84.7%	2.6%	6.1%	1.2%	90.1%	8.4%	10.8%	3.4%	77.3%
2012	2.8%	6.3%	2.1%	88.9%	1.5%	6.4%	1.1%	91.1%	8.0%	10.5%	5.0%	76.6%
2013	2.3%	7.8%	1.9%	87.9%	1.1%	5.9%	0.7%	92.2%	8.1%	10.7%	3.9%	77.4%
2014	2.5%	9.3%	3.0%	85.3%	1.8%	5.8%	0.9%	91.5%	7.2%	15.2%	5.4%	72.2%
2015	3.7%	9.6%	1.5%	85.2%	1.3%	5.5%	1.2%	91.9%	6.0%	17.2%	4.1%	72.7%
2016	2.6%	7.7%	3.1%	86.6%	1.7%	5.5%	1.2%	91.7%	4.7%	15.8%	4.4%	75.2%
2017	2.3%	5.8%	3.1%	88.9%	0.5%	5.1%	0.6%	93.7%	4.8%	9.3%	5.9%	80.0%
2018	2.5%	7.4%	3.6%	86.6%	0.8%	5.3%	0.6%	93.3%	5.1%	8.7%	7.9%	78.3%

Generator Forced Outage Rates

There are three primary forced outage rate metrics. The most fundamental forced outage rate metric is EFORd. The other forced outage rate metrics either exclude some outages, XEFORd, or exclude some outages and exclude some time periods, EFORp. The other outage rate metrics will no longer be used under the capacity performance capacity market design.

The unadjusted forced outage rate of a generating unit is measured as the equivalent demand forced outage rate (EFORd). EFORd is a measure of the probability that a generating unit will fail, either partially or totally, to perform when it is needed to operate. EFORd measures the forced outage rate during periods of demand, and does not include planned or maintenance outages. A period of demand is a period during which a generator is running or needed to run. EFORd calculations use historical performance data, including equivalent forced outage hours, service hours, average forced outage duration, average run time, average time between unit starts, available hours and period hours.[122] The EFORd metric includes all forced outages, regardless of the reason for those outages.

The average PJM EFORd for 2018 was 7.2 percent, an increase from 7.1 percent for 2017. Figure 5-11 shows the average EFORd since 1999 for all units in PJM.[123]

122 Equivalent forced outage hours are the sum of all forced outage hours in which a generating unit is fully inoperable and all partial forced outage hours in which a generating unit is partially inoperable prorated to represent full hours.

123 The universe of units in PJM changed as the PJM footprint expanded and as units retired from and entered PJM markets. See the *2018 State of the Market Report for PJM*, Appendix A: "PJM Geography" for details.

Figure 5-11 Trends in the equivalent demand forced outage rate (EFORd): 1999 through 2018

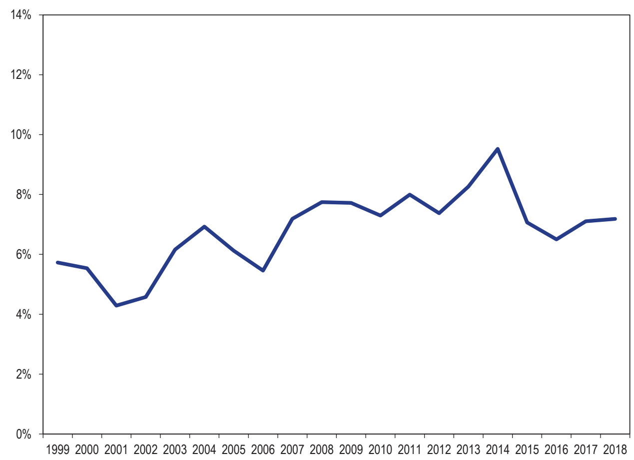


Table 5-31 shows the class average EFORd by unit type.

Table 5-31 EFORd data for different unit types: 2007 through 2018

	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Coal	8.8%	8.9%	8.4%	9.4%	10.5%	9.7%	11.0%	11.8%	9.4%	10.4%	12.5%	13.1%
Combined Cycle	3.7%	3.5%	3.7%	2.7%	3.2%	4.5%	3.0%	4.5%	2.9%	3.7%	2.6%	2.3%
Combustion Turbine	11.7%	11.2%	9.8%	9.1%	8.3%	8.5%	11.1%	15.8%	9.2%	6.1%	5.9%	6.7%
Diesel	11.7%	10.3%	9.3%	6.4%	9.3%	5.1%	6.6%	14.8%	9.1%	7.2%	7.6%	7.2%
Hydroelectric	2.0%	2.0%	3.2%	1.2%	2.9%	4.4%	3.6%	3.8%	5.2%	3.7%	3.2%	3.2%
Nuclear	1.4%	1.9%	4.1%	2.5%	2.8%	1.6%	1.2%	1.9%	1.4%	1.9%	0.6%	0.8%
Other	11.1%	15.5%	14.3%	12.3%	14.9%	12.3%	15.5%	14.5%	13.0%	9.2%	13.8%	11.8%
Total	7.2%	7.7%	7.7%	7.3%	8.0%	7.4%	8.3%	9.5%	7.1%	6.5%	7.1%	7.2%

Other Forced Outage Rate Metrics

There are a number of performance incentives in the current capacity market design, but they fall short of the incentives that a unit would face if it earned all its revenue in an energy market. These incentives will change when the capacity performance capacity market design is implemented beginning with the 2018/2019 Delivery Year but remain essential reasons why the incentive components of capacity performance design were necessary.

Currently, there are two additional forced outage rate metrics that play a significant role in PJM markets, XEFORd and EFORp. Under the capacity performance modifications to RPM, neither XEFORd nor EFORp will be relevant.

The XEFORd metric is the EFORd metric adjusted to remove outages that have been defined to be outside management control (OMC). Under the capacity performance modifications to RPM, all outages will be included in the EFORd metric used to determine the level of unforced capacity for specific units that must be offered in PJM's Capacity Market, including the outages previously designated as OMC. OMC outages will no longer be excluded from the EFORd calculations.

The EFORp metric is the EFORd metric adjusted to remove OMC outages and to reflect unit availability only during the approximately 500 hours defined in the PJM RPM tariff to be the critical load hours. Under the capacity performance modifications to RPM, EFORp will no longer be used to calculate performance penalties.

Current PJM capacity market rules use XEFORd to determine the UCAP for generating units. Unforced capacity in the PJM Capacity Market for any individual generating unit is equal to one minus the XEFORd multiplied by the unit ICAP.

The current PJM capacity market rules create an incentive to minimize the forced outage rate excluding OMC outages, but not an incentive to minimize the forced outage rate accounting for all forced outages. In fact, because PJM uses XEFORd as the outage metric to define capacity available for sale, the current PJM Capacity Market includes an incentive to classify as many forced outages as possible as OMC. That incentive is removed in the capacity performance design.

Outages Deemed Outside Management Control

OMC outages will continue to be excluded from outage rate calculations through the end of the 2017/2018 Delivery Year. Under the capacity performance modifications to RPM, effective with the 2018/2019 Delivery Year, OMC outages will no longer be excluded from the EFORd metric used to determine the level of unforced capacity for specific units that must be offered in PJM's Capacity Market. All forced outages will be included.[124]

124 "Reliability Assurance Agreement Among Load Serving Entities in the PJM Region," Schedule 5.B.

Table 5-32 shows OMC forced outages by cause code, as classified by PJM. OMC forced outages accounted for 1.2 percent of all forced outages in 2018. The largest contributor to OMC outages, wet coal, was the cause of 25.8 percent of OMC outages and 0.3 percent of all forced outages.

Table 5-32 OMC outages: 2018

OMC Cause Code	Percent of OMC Forced Outages	Percent of all Forced Outages
Wet coal	25.8%	0.3%
Other switchyard equipment	15.6%	0.2%
Switchyard circuit breakers	10.0%	0.1%
Other miscellaneous external problems	9.8%	0.1%
Flood	8.0%	0.1%
Transmission system problems other than catastrophes	6.1%	0.1%
Lack of fuel	5.9%	0.1%
Transmission line	5.1%	0.1%
Lightning	3.6%	0.0%
Switchyard transformers and associated cooling systems	2.6%	0.0%
Lack of water (hydro)	2.3%	0.0%
Transmission equipment	1.3%	0.0%
Storms	1.2%	0.0%
Switchyard system protection devices	1.1%	0.0%
Other fuel quality problems	0.9%	0.0%
Transmission equipment beyond the 1st substation	0.4%	0.0%
Low Btu coal	0.1%	0.0%
Other catastrophe	0.0%	0.0%
Regulatory	0.0%	0.0%
Hurricane	0.0%	0.0%
Total	100.0%	1.2%

Forced Outage Analysis

The MMU analyzed the causes of forced outages for the entire PJM system. The metric used was lost generation, which is the product of the duration of the outage and the size of the outage reduction. Lost generation can be converted into lost system equivalent availability.[125] On a system wide basis, the resultant lost equivalent availability from the forced outages is equal to the equivalent forced outage factor (EFOF).[126]

PJM EFOF was 4.4 percent in 2018. This means there was 4.4 percent lost availability because of forced outages. Table 5-33 shows that forced outages for boiler tube leaks, at 18.8 percent of the system wide EFOF, were the largest single contributor to EFOF.

125 For any unit, lost generation can be converted to lost equivalent availability by dividing lost generation by the product of the generating units' capacity and period hours. This can also be done on a system wide basis.

126 EFOF incorporates all outages regardless of their designation as OMC.

Table 5-33 Contribution to EFOF by unit type by cause: 2018

	Coal	Combined Cycle	Combustion Turbine	Diesel	Hydroelectric	Nuclear	Other	System
Boiler Tube Leaks	24.4%	3.0%	0.0%	0.0%	0.0%	0.0%	14.8%	18.8%
Wet Scrubbers	10.9%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	7.7%
Boiler Air and Gas Systems	7.7%	0.0%	0.0%	0.0%	0.0%	0.0%	3.7%	5.8%
Unit Testing	4.6%	3.0%	10.1%	40.4%	6.1%	7.3%	8.2%	5.6%
Economic	0.5%	2.1%	7.1%	4.5%	2.9%	0.0%	33.5%	4.5%
Low Pressure Turbine	4.0%	0.7%	0.0%	0.0%	0.0%	0.0%	5.8%	3.4%
Feedwater System	3.2%	1.5%	0.0%	0.0%	0.0%	23.8%	1.1%	3.4%
Boiler Fuel Supply from Bunkers to Boiler	4.5%	0.4%	0.0%	0.0%	0.0%	0.0%	0.4%	3.2%
Miscellaneous (Generator)	2.4%	5.1%	10.6%	5.4%	4.1%	0.0%	2.4%	3.1%
Electrical	2.3%	4.2%	6.4%	1.4%	1.9%	2.7%	4.8%	3.0%
Miscellaneous (Pollution Control Equipment)	4.0%	0.0%	0.1%	0.0%	0.0%	0.0%	0.3%	2.9%
Intermediate Pressure Turbine	3.7%	0.0%	0.0%	0.0%	0.0%	0.0%	1.0%	2.7%
Fuel Quality	3.5%	0.0%	0.2%	3.7%	0.0%	0.0%	0.9%	2.6%
Circulating Water Systems	2.0%	9.0%	0.0%	0.0%	0.0%	5.7%	2.2%	2.3%
Auxiliary Systems	1.1%	6.3%	11.2%	0.0%	0.3%	0.1%	0.9%	2.0%
Miscellaneous (Steam Turbine)	0.6%	18.6%	0.0%	0.0%	0.0%	8.0%	0.4%	1.8%
Boiler Tube Fireside Slagging or Fouling	2.4%	0.0%	0.0%	0.0%	0.0%	0.0%	0.2%	1.7%
Boiler Piping System	1.9%	3.5%	0.0%	0.0%	0.0%	0.0%	1.3%	1.7%
Condensing System	1.8%	0.3%	0.0%	0.0%	0.0%	3.8%	0.3%	1.4%
All Other Causes	14.6%	42.3%	54.3%	44.5%	84.7%	48.6%	18.0%	22.6%
Total	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%

Table 5-34 shows the categories which are included in the economic category.[127] Lack of fuel that is considered outside management control accounted for 1.7 percent of all economic reasons.

OMC lack of fuel is described as "Lack of fuel where the operator is not in control of contracts, supply lines, or delivery of fuels."[128] Only a handful of units use other economic problems to describe outages. Other economic problems are not defined by NERC GADS and are best described as economic problems that cannot be classified by the other NERC GADS economic problem cause codes. Lack of water events occur when a hydroelectric plant does not have sufficient fuel (water) to operate.

Table 5-34 Contributions to economic outages: 2018

	Contribution to Economic Reasons
Lack of fuel (Non-OMC)	93.7%
Fuel conservation	1.8%
Lack of fuel (OMC)	1.7%
Other economic problems	1.2%
Problems with primary fuel for units with secondary fuel operation	0.9%
Lack of water (hydro)	0.6%
Wet fuel (biomass)	0.2%
Ground water or other water supply problems	0.0%
Total	100.0%

EFORd, XEFORd and EFORp

The equivalent forced outage rate during peak hours (EFORp) is a measure of the probability that a generating unit will fail, either partially or totally, to perform when it is needed to operate during the peak hours of the day in the peak months of January, February, June, July and August. EFORp is calculated using historical performance data and is designed to measure if a unit would have run had the unit not been forced out. Like XEFORd, EFORp excludes OMC outages. PJM systemwide EFORp is a capacity-weighted average of individual unit EFORp.

127 The definitions of these outages are defined by NERC GADS.
128 The definitions of these outages are defined by NERC GADS.

Until the capacity performance market design is fully implemented for the 2020/2021 Delivery Year, EFORp will be used in the calculation of nonperformance charges for units that are not capacity performance capacity resources. Under capacity performance, EFORp will not be used.

EFORd, XEFORd and EFORp are designed to measure the rate of forced outages, which are defined as outages that cannot be postponed beyond the end of the next weekend.[129] It is reasonable to expect that units have some degree of control over when to take a forced outage, depending on the underlying cause of the forced outage. If units had no control over the timing of forced outages, outages during peak hours of the peak months would be expected to occur at roughly the same rate as outages during periods of demand throughout the rest of the year. With the exception of nuclear units, EFORp is lower than XEFORd, suggesting that units elect to take non-OMC forced outages during off-peak hours, as much as it is within their ability to do so. That is consistent with the incentives created by the PJM Capacity Market but it does not directly address the question of the incentive effect of omitting OMC outages from the EFORp metric.

Table 5-35 shows the capacity-weighted class average of EFORd, XEFORd and EFORp.

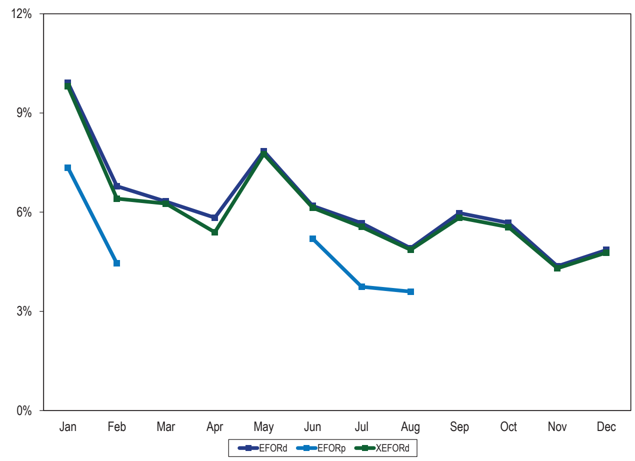
Table 5-35 EFORd, XEFORd and EFORp data by unit type: 2018[130]

	EFORd	XEFORd	EFORp	Difference EFORd and XEFORd	Difference EFORd and EFORp
Coal	13.1%	13.1%	10.0%	0.1%	3.1%
Combined Cycle	2.3%	2.2%	1.7%	0.0%	0.6%
Combustion Turbine	6.7%	6.3%	3.9%	0.4%	2.8%
Diesel	7.2%	6.9%	5.3%	0.2%	1.9%
Hydroelectric	3.2%	3.1%	2.1%	0.1%	1.1%
Nuclear	0.8%	0.8%	0.6%	0.0%	0.2%
Other	11.8%	11.1%	6.0%	0.7%	5.8%
Total	7.2%	7.0%	5.0%	0.2%	2.2%

Performance by Month

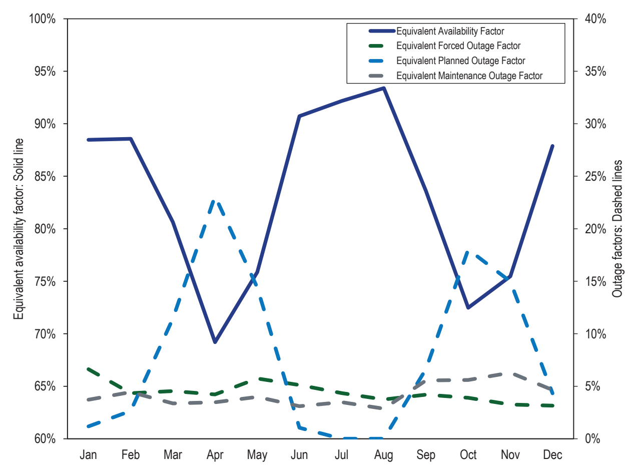
On a monthly basis, EFORp values were less than EFORd and XEFORd values as shown in Figure 5-12, demonstrating that units had fewer non-OMC outages during peak hours than would have been expected based on EFORd.

Figure 5-12 EFORd, XEFORd and EFORp: 2018



On a monthly basis, unit availability as measured by the equivalent availability factor is shown in Figure 5-13.

Figure 5-13 Monthly generator performance factors: 2018



129 See "PJM Manual 22: Generator Resource Performance Indices," § 2.0 Definitions, Rev. 17 (April 1, 2017).

130 EFORp is only calculated for the peak months of January, February, June, July and August.

Demand Response

Markets require both a supply side and a demand side to function effectively. The demand side of wholesale electricity markets is underdeveloped. Wholesale power markets will be more efficient when the demand side of the electricity market becomes fully functional without depending on special programs as a proxy for full participation.

Overview

- **Demand Response Activity.** Demand response activity includes economic demand response (economic resources), emergency and pre-emergency demand response (demand resources), synchronized reserves and regulation. Economic demand response participates in the energy market. Emergency and pre-emergency demand response participates in the capacity market and energy market.[1] Demand response resources participate in the Synchronized Reserve Market. Demand response resources participate in the Regulation Market.

  In 2018, total demand response revenue increased by $95.9 million, 19.1 percent, from $502.7 million in 2017 to $598.6 million in 2018. Emergency demand response revenue accounted for 98.1 percent of all demand response revenue, economic demand response for 0.4 percent, demand response in the Synchronized Reserve Market for 1.0 percent and demand response in the regulation market for 0.5 percent.

  Total emergency demand response revenue increased by $91.8 million, 18.5 percent, from $495.2 million in 2017 to $587.0 million in 2018. This increase consisted entirely of capacity market revenue.[2]

  Economic demand response revenue decreased by $0.1 million, 3.9 percent, from $2.7 million in 2017 to $2.6 million in 2018.[3] Demand response revenue in the Synchronized Reserve Market increased by $2.9 million, 98.4 percent, from $3.0 million in 2017 to $5.9 million in 2018. Demand response revenue in the regulation market increased by $1.2 million, 66.1 percent, from $1.8 million in 2017 to $3.1 million in 2018.

- **Demand Response Energy Payments are Uplift.** Energy payments to emergency and economic demand response resources are uplift. LMP does not cover energy payments although emergency and economic demand response can and does set LMP. Energy payments to emergency demand resources are paid by PJM market participants in proportion to their net purchases in the real-time market. Energy payments to economic demand resources are paid by real-time exports from PJM and real-time loads in each zone for which the load-weighted average real-time LMP for the hour during which the reduction occurred is greater than or equal to the net benefits test price for that month.[4]

- **Demand Response Market Concentration.** The ownership of economic demand response resources was highly concentrated in 2017 and 2018. The HHI for economic resource reductions decreased by 40 points from 7590 in 2017 to 7540 in 2018. The ownership of emergency demand response resources was moderately concentrated in 2018. The HHI for emergency demand response committed MW was 1433 for the 2017/2018 Delivery Year and 1922 for the 2018/2019 Delivery Year. In the 2017/2018 Delivery Year, the four largest companies owned 69.6 percent of all committed emergency demand response MW. In the 2018/2019 Delivery Year, the four largest companies owned 77.9 percent of all committed emergency demand response MW.

- **Limited Locational Dispatch of Demand Resources.** Beginning with the 2014/2015 Delivery Year, demand resources are dispatchable for mandatory reductions on a subzonal basis, defined by zip codes, but only if the subzone is defined at least one day before it is dispatched and only until PJM removes the definition of the subzone. Nodal dispatch of demand resources in a nodal market would improve market efficiency. The goal should be nodal dispatch of demand resources with no advance notice required, as is the case for generation resources. With full implementation of the Capacity Performance rules in the capacity market starting with the 2020/2021 Delivery Year, PJM will be able

1 Emergency demand response refers to both emergency and pre-emergency demand response. With the implementation of the Capacity Performance design, there is no functional difference between the emergency and pre-emergency demand response resource.

2 The total credits and MWh numbers for demand resources were calculated as of March 1, 2019 and may change as a result of continued PJM billing updates.

3 Economic credits are synonymous with revenue received for reductions under the economic load response program.

4 "PJM Manual 28: Operating Agreement Accounting," § 11.2.2 Economic Load Response Program, Rev. 81 (Oct. 25, 2018).

to individually dispatch demand resources with no advanced notice although PJM does not know the nodal location of demand resources.

Recommendations

The MMU recognizes that PJM incorporated some of the recommendations related to demand response in the Capacity Performance filing. The status of each recommendation reflects the status at December 31, 2018.

- The MMU recommends, as a preferred alternative to including demand resources as supply in the capacity market, that demand resources be on the demand side of the markets, that customers be able to avoid capacity and energy charges by not using capacity and energy at their discretion, that customer payments be determined only by metered load, and that PJM forecasts immediately incorporate the impacts of demand side behavior. (Priority: High. First reported 2014. Status: Not adopted.)
- The MMU recommends that the option to specify a minimum dispatch price (strike price) for demand resources be eliminated and that participating resources receive the hourly real-time LMP less any generation component of their retail rate. (Priority: Medium. First reported 2010. Status: Not adopted.)
- The MMU recommends that the maximum offer for demand resources be the same as the maximum offer for generation resources. (Priority: Medium. First reported 2013. Status: Not adopted.)
- The MMU recommends that the demand resources be treated as economic resources, responding to economic price signals like other capacity resources. The MMU recommends that demand resources not be treated as emergency resources, not trigger a PJM emergency and not trigger a Performance Assessment Interval. (Priority: High. First reported 2012. Status: Not adopted.)
- The MMU recommends that the Emergency Program Energy Only option be eliminated because the opportunity to receive the appropriate energy market incentive is already provided in the economic program. (Priority: Low. First reported 2010. Status: Not adopted.)
- The MMU recommends that, if demand resources remain in the capacity market, a daily energy market must offer requirement apply to demand resources, comparable to the rule applicable to generation capacity resources.[5] (Priority: High. First reported 2013. Status: Not adopted.)
- The MMU recommends that demand resources be required to provide their nodal location, comparable to generation resources. (Priority: High. First reported 2011. Status: Not adopted.)
- The MMU recommends that PJM require nodal dispatch of demand resources with no advance notice required or, if nodal location is not required, subzonal dispatch of demand resources with no advance notice required. (Priority: High. First reported 2015. Status: Not adopted.)
- The MMU recommends that PJM not remove any defined subzones and maintain a public record of all created and removed subzones. (Priority: Low. First reported 2016. Status: Not adopted.)
- The MMU recommends that PJM eliminate the measurement of compliance across zones within a compliance aggregation area (CAA). The multiple zone approach is less locational than the zonal and subzonal approach and creates larger mismatches between the locational need for the resources and the actual response. (Priority: High. First reported 2015. Status: Not adopted.)
- The MMU recommends that measurement and verification methods for demand resources be modified to reflect compliance more accurately. (Priority: Medium. First reported 2009. Status: Not adopted.)
- The MMU recommends that compliance rules be revised to include submittal of all necessary hourly load data, and that negative values be included when calculating event compliance across hours and registrations. (Priority: Medium. First reported 2012. Status: Not adopted.)
- The MMU recommends that PJM adopt the ISO-NE five-minute metering requirements in order to ensure that dispatchers have the necessary information for reliability and that market payments

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

to demand resources be calculated based on interval meter data at the site of the demand reductions.[6] (Priority: Medium. First reported 2013. Status: Not adopted.)

- The MMU recommends 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. (Priority: Medium. First reported 2013. Status: Partially adopted.)
- The MMU recommends that load management testing be initiated by PJM with limited warning to CSPs in order to more accurately represent the conditions of an emergency event. (Priority: Low. First reported 2012. Status: Not adopted.)
- The MMU recommends that shutdown cost be defined as the cost to curtail load for a given period that does not vary with the measured reduction or, for behind the meter generators, be the start cost defined in Manual 15 for generators. (Priority: Low. First reported 2012. Status: Not adopted.)
- The MMU recommends that the Net Benefits Test be eliminated and that demand response resources be paid LMP less any generation component of the applicable retail rate. (Priority: Low. First reported 2015. Status: Not adopted.)
- The MMU recommends that the tariff rules for demand response clarify that a resource and its CSP, if any, must notify PJM of material changes affecting the capability of the resource to perform as registered and must terminate or modify registrations that are no longer capable of responding to PJM dispatch directives at defined levels because load has been reduced or eliminated, as in the case of bankrupt and/or out of service facilities. (Priority: Medium. First reported 2015. Status: Not adopted.)
- The MMU recommends that there be only one demand response product in the capacity market, with an obligation to respond when called for any hour of the delivery year. (Priority: High. First reported 2011. Status: Partially adopted.[7])
- The MMU recommends that the lead times for demand resources be shortened to 30 minutes with an hour minimum dispatch for all resources. (Priority: Medium. First reported 2013. Status: Partially adopted.)
- The MMU recommends setting the baseline for measuring capacity compliance under winter compliance at the customers' PLC, similar to GLD, to avoid double counting. (Priority: High. First reported 2010. Status: Partially adopted.)
- The MMU recommends the Relative Root Mean Squared Test be required for all demand resources with a CBL. (Priority: Low. First reported 2017. Status: Partially adopted.)
- The MMU recommends that PRD be required to respond during a PAI to be consistent with all CP resources. (Priority: High. First reported 2017. Status: Not adopted.)
- The MMU recommends that the limits imposed on the pre-emergency and emergency demand response share of the Synchronized Reserve Market be eliminated. (Priority: Medium. New recommendation. Status: Not adopted.)
- The MMU recommends that 30 minute pre-emergency and emergency demand response be considered to be 30 minute reserves. (Priority: Medium. New recommendation. Status: Not adopted.)
- 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 with the existing lag. (Priority: Medium. New recommendation. Status: Not adopted.)

Conclusion

A fully functional demand side of the electricity market means that end use customers or their designated intermediaries will have the ability to see real-time energy price signals in real time, will have the ability to react to real-time prices in real time and will have the

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

7 PJM's Capacity Performance design requires resources to respond when called for any hour of the delivery year.

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

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

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

In order to be a substitute for generation, demand resources should be defined in PJM rules as an economic resource, as generation is defined. Demand resources should be required to offer in the Day-Ahead Energy Market and should be called when the resources are required and prior to the declaration of an emergency. Demand resources should be available for every hour of the year. The fact that PJM currently defines demand resources as emergency resources and the fact that calling on demand resources triggers a performance assessment interval (PAI) under the Capacity Performance design, both serve as a significant disincentive to calling on demand resources and mean that demand resources are underused. Demand resources should be treated as economic resources like any other capacity resource. Demand resources should be called when economic and paid the LMP rather than an inflated strike price up to $1,849 per MWh that is set by the seller.

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

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

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

In order to be a substitute for generation, reductions should be calculated hourly for dispatched DR. The current rules use the average reduction for the duration of an event. The average reduction across multiple hours does not provide an accurate metric for each hour of the event and is inconsistent with the measurement of generation resources. Measuring compliance hourly would provide accurate information to the PJM system.

Under the new CP rules, the performance of demand response during Performance Assessment Interval (PAI) will be measured on a five-minute basis.

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

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

The MMU peak shaving proposal at the Summer-Only Demand Response Senior Task Force (SODRSTF) is an example of how to create a demand side product that is on the demand side of the market and not on the supply side.[8] The MMU proposal was based on the BGE load forecasting program and Pennsylvania Act 129 Utility Program.[9] [10] Under the MMU proposal, participating load would inform PJM prior to an RPM auction of the MW participating, the months and hours of participation and the temperature humidity index (THI) threshold at which load would be reduced. PJM would reduce the load forecast used in the RPM auction based on the designated reductions. Load would agree to curtail demand to at or below a defined FSL, less than the customer PLC, when the THI exceeds a defined level or load exceeds a specified threshold. By relying on metered load and the PLC, load can reduce its demand for capacity and that reduction can be verified without complicated and inaccurate metrics to estimate load reductions. Under PJM's weakened version of the program, performance will be measured under the current economic demand response CBL rules which means relying on load estimates rather than actual metered load.[11] PJM's proposal includes only a THI curtailment trigger and not an overall load curtailment trigger.

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

Under this approach, customers that wish to avoid capacity payments would reduce their load during expected high load hours. Capacity costs would be assigned to LSEs and by LSEs to customers, based on actual load on the system during these critical hours. Customers wishing to avoid high energy prices would reduce their load during high price hours. Customers would pay for what they actually use, as measured by meters, rather than relying on flawed measurement and verification methods. No M&V estimates are required. No promises of future reductions which can only be verified by M&V are required. To the extent that customers enter into contracts with CSPs or LSEs to manage their payments, M&V can be negotiated as part of a bilateral commercial contract between a customer and its CSP or LSE.

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

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

9 *Advance signals that can be used to foresee demand response days*, BGE, <https://www.pjm.com/-/media/committees-groups/task-forces/sodrstf/20180309/20180309-item-05-bge-load-curtailment-programs.ashx> (Accessed March 6, 2019).

10 *Pennsylvania ACT 129 Utility Program*, CPower, <https://www.pjm.com/-/media/committees-groups/task-forces/sodrstf/20180413/20180413-item-03-pa-act-129-program.ashx>, (Accessed March 6, 2019).

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

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

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

PJM Demand Response Programs

All PJM demand response programs can be grouped into economic, emergency and pre-emergency programs, or Price Responsive Demand (PRD). Under current rules, there is no functional difference between pre-emergency and emergency demand resources. Table 6-1 provides an overview of the key features of PJM demand response programs.

The current PRD rules do not align with the definition of capacity under the Capacity Performance construct despite PJM's attempt to create alignment.[12] The PJM proposed rule changes do not require reductions during PAI unless LMP is above the specified price threshold. PJM incorrectly values PRD capacity and measured performance.[13] Similar to emergency and pre-emergency demand response, PJM would limit the nominated MW for PRD resources to the lower of the Peak Load Contribution (PLC) minus the Firm Service Level (FSL) times the loss factor (LF) or the Winter Peak Load (WPL) multiplied by the Zonal Winter Weather Adjustment Factor (ZWWAF) minus the winter Firm Service Level (wFSL) times the loss factor for each zone.

Use of the WPL would artificially limit the amount of MW that can participate as PRD if the WPL is less than the PLC.

Demand response activity includes economic demand response (economic resources), emergency and pre-emergency demand response (demand resources), synchronized reserves and regulation. Economic demand response participates in the energy market. Emergency and pre-emergency demand response participate in the capacity market and energy market.[14] Demand response resources participate in the Synchronized Reserve Market. Demand response resources participate in the regulation market.

All demand resources must register as pre-emergency unless the participant relies on behind the meter generation and the resource has environmental restrictions that limit the resource's ability to operate only in emergency conditions.[15] Under current rules, PJM will declare an emergency if pre-emergency or emergency demand response is dispatched. In all demand response programs, CSPs are companies that sign up customers that have the ability to reduce load. After a demand response event occurs, PJM compensates CSPs for their participants' load reductions and CSPs in turn compensate their participants. Only CSPs are eligible to participate in the PJM demand response programs, but a participant can register as a PJM special member and become a CSP without any additional cost.

PRD does not receive direct capacity or energy payments. PRD reduces the amount of capacity that must be purchased by the LSE and therefore reduces the LSE's payments for capacity. When PRD load is not on the system, that load also avoids paying for the associated energy. PRD meets its obligation by responding when LMP is at or above price thresholds defined in the PRD plan.[16] PRD does not have to respond during performance assessment intervals (PAI) and therefore is inferior to other capacity resources and is not a substitute for other capacity resources in the capacity performance construct. The MMU recommends that PRD be required to respond during a PAI to be consistent with all CP

12 See "Proposed Amendments to Price Response Demand Rules," Docket No. ER19-1012-000 (February 7, 2019).

13 See "Comments of the Independent Market Monitor for PJM," Docket No. ER19-1012 (February 28, 2019).

14 Emergency demand response refers to both emergency and pre-emergency demand response. With the implementation of the Capacity Performance design, there is no functional difference between the emergency and pre-emergency demand response resource.

15 OA Schedule 1 § 8.5.

16 The Demand Response Subcommittee (DRS) is currently working to align PRD with the CP designed products.

resources. PRD first cleared the capacity market in the BRA for the 2020/2021 Delivery Year, and cleared for the 2021/2022 Delivery Year.[17]

Table 6-1 Overview of demand response programs

	Emergency and Pre-Emergency Load Response Program			Economic Load Response Program	Price Responsive Demand
	Load Management (LM)				
Market	Capacity Only	Capacity and Energy	Energy Only	Energy Only	Capacity Only
Capacity Market	DR cleared in RPM	DR cleared in RPM	Not included in RPM	Not included in RPM	PRD cleared in RPM
Dispatch Requirement	Mandatory Curtailment	Mandatory Curtailment	Voluntary Curtailment	Dispatched Curtailment	Price Threshold
Penalties	RPM event or test compliance penalties	RPM event or test compliance penalties	NA	NA	RPM event or test compliance penalties
Capacity Payments	Capacity payments based on RPM clearing price	Capacity payments based on RPM clearing price	NA	NA	Avoided capacity costs
Energy Payments	No energy payment	Energy payment based on submitted higher of "minimum dispatch price" and LMP. Energy payment during PJM declared Emergency Event mandatory curtailments.	Energy payment based on submitted higher of "minimum dispatch price" and LMP. Energy payment only for voluntary curtailments.	Energy payment based on full LMP. Energy payment for hours of dispatched curtailment.	NA

Non-PJM Demand Response Programs

Within the PJM footprint, states may have additional demand response programs as part of a Renewable Portfolio Standard (RPS) or a separate program. Indiana, Ohio, Pennsylvania and North Carolina include demand response in their RPS. If demand response is dispatched by a state run program, the demand response resources are ineligible to receive payments from PJM during the state dispatch.

Participation in Demand Response Programs

On April 1, 2012, FERC Order No. 745 was implemented in the PJM economic program, requiring payment of full LMP for dispatched demand resources when a net benefits test (NBT) price threshold is exceeded. This approach replaced the payment of LMP minus the charges for wholesale power and transmission included in customers' tariff rates.

Order No. 719 required PJM and other RTOs to amend their market rules to accept bids from aggregators of retail customers of utilities unless the laws or regulations of the relevant electric retail regulatory authority ("RERRA") do not permit the customers aggregated in the bid to participate.[18] PJM implemented rules that require PJM to verify with EDCs that no law or regulation of a RERRA prohibits an end use customers' participation.[19] EDCs and their end use customers are categorized as small and large based on whether the EDC distributed more or less than 4 million MWh in the previous fiscal year. End use customers within a large EDC must provide verification of any other contractual obligations or laws or regulations that prohibit participation, but end use customers within a small EDC do not need to provide additional verification.[20] RERRAs have permitted EDCs, in a number of cases, to participate in the PJM Economic Load Response Program. There are 188 active RERRAs within PJM.

Figure 6-1 shows all revenue from PJM demand response programs by market for 2008 through 2018. Since the implementation of the RPM Capacity Market on June 1, 2007, the capacity market (demand resources) has been the primary source of demand response revenue.[21]

17 There were a total of 558 MW of cleared PRD in the 2020/2021 Delivery Year. See PJM Auction Results, <https://www.pjm.com/-/media/markets-ops/rpm/rpm-auction-info/2020-2021-base-residual-auction-results.ashx?la=en>.

18 *Wholesale Competition in Regions with Organized Electric Markets*, Order No. 719, FERC Stats. & Regs. ¶ 31,281 at P 154 (2008), *order on reh'g*, Order No. 719-A, FERC Stats. & Regs. ¶ 31,292, *order on reh'g*, Order No. 719-B, 129 FERC ¶ 61,252 (2009).

19 The evidence supplied by LDCs must take the form of an order, resolution or ordinance of the RERRA, an opinion of the RERRA's legal counsel attesting to existence of an order, resolution, or ordinance, or an opinion of the state attorney general on behalf of the RERRA attesting to existence of an order, resolution or ordinance.

20 PJM Operating Agreement Schedule 1 § 1.5A.3.1.

21 This includes both capacity market revenue and emergency energy revenue for capacity resources.

In 2018, total demand response revenue increased by $95.8 million, 19.1 percent, from $502.7 million in 2017 to $598.6 million in 2018. Total emergency demand response revenue increased by $91.8 million, 18.5 percent, from $495.2 million in 2017 to $587.0 million in 2018. This increase consisted entirely of capacity market revenue.[22] In 2018, demand resource revenue, which includes capacity and emergency energy revenue, accounted for 98.1 percent of all revenue received by demand response providers, the economic program for 0.4 percent, synchronized reserve for 1.0 percent and the regulation market for 0.5 percent.

Economic demand response revenue decreased by $0.1 million, 3.5 percent, from $2.7 million in 2017 to $2.6 million in 2018.[23] Demand response revenue in the Synchronized Reserve Market increased by $2.9 million, 98.4 percent, from $3.0 million in 2017 to $5.9 million in 2018. Demand response revenue in the regulation market increased by $1.2 million, 66.1 percent, from $1.8 million in 2017 to $3.1 million in 2018.

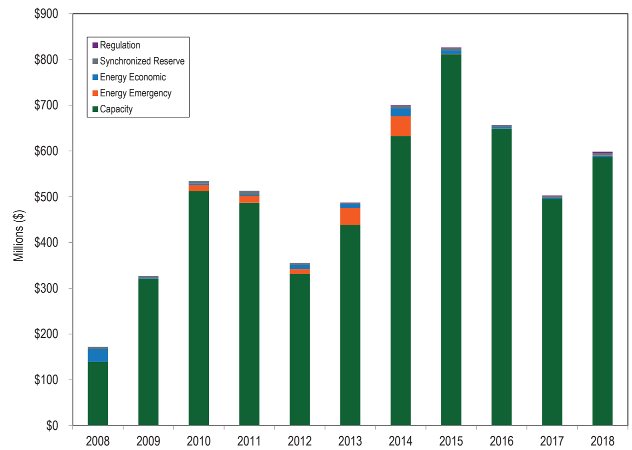
Higher demand resource revenues were in part a result of higher capacity market prices in 2018. The capacity revenue in 2017 is from 2016/2017 and 2017/2018 RPM auction clearing prices and the capacity revenue in 2018 is from 2017/2018 and 2018/2019 RPM auction clearing prices. Average capacity market prices increased $34.39 per MW-day from $141.19 in the 2017/2018 Delivery Year to $175.58 in the 2018/2019 Delivery Year, a 24.4 percent increase.[24]

22 The total credits and MWh for demand resources were calculated as of March 1, 2019 and may change as a result of continued PJM billing updates. There was no emergency energy revenue in 2018.

23 Economic credits are synonymous with revenue received for reductions under the economic load response program.

24 See the *2018 State of the Market Report for PJM*, Section 7: Net Revenue, Table 7-6.

Figure 6-1 Demand response revenue by market: 2008 through 2018



Economic Program

FERC Order No. 831 requires all energy offers above $1,000 per MWh to provide supporting documentation.[25] Economic resources offer into the energy market and must provide supporting documentation to offer above $1,000 per MWh. FERC stated, "[t]he offer cap reforms, however, do not apply to capacity-only demand response resources that do not submit incremental energy offers into energy markets."[26] Demand resources participate in both the capacity and energy markets and are not capacity only resources. It is not clear whether FERC intended to exclude demand resources with high strike prices from the requirements of Order 831. Demand resources should not be permitted to make offers above $1,000 per MWh without the same verification requirements applied to economic resources or generation resources. The MMU recommends that the rules for maximum offer for the emergency and pre-emergency program match the maximum offer for generation resources.

Table 6-2 shows registered sites and MW for the last day of each month for the period January 1, 2014, through December 31, 2018. Registration is a prerequisite for CSPs to participate in the economic program. The monthly average number of registrations for economic demand response decreased and the monthly average registered MW increased in 2018 compared to 2017. Average monthly registrations decreased by 268, 38.0 percent, from 706 in 2017 to 438 in 2018. Average

25 157 FERC ¶ 61,115 (2016).

26 *Id.* at 8.

monthly registered MW increased by 606 MW, 30.3 percent, from 2,000 MW in 2017 to 2,606 MW in 2018.

Most demand response resources are registered for both the economic and emergency demand response programs. There were 1,671 registrations and 1,265 nominated MW in the emergency program also registered in the economic program during 2018.

Table 6-2 Economic program registrations on the last day of the month: 2014 through 2018[27]

	2014		2015		2016		2017		2018	
Month	Registrations	Registered MW	Registrations	Registered MW	Registrations	Registered MW	Registrations	Registered MW	Registrations	Registered MW
Jan	1,180	2,325	1,078	2,960	838	2,557	871	2,603	537	2,570
Feb	1,174	2,330	1,076	2,956	835	2,557	842	2,578	537	2,628
Mar	1,185	2,692	1,075	2,949	834	2,556	850	2,576	519	2,641
Apr	1,194	2,827	1,076	2,938	832	2,556	897	2,574	501	2,624
May	745	2,511	980	2,846	829	2,545	977	2,626	471	2,615
Jun	928	2,943	871	2,614	518	2,500	577	1,305	397	2,576
Jul	1,036	3,006	870	2,609	519	2,421	589	1,548	374	2,591
Aug	1,080	3,033	869	2,609	805	2,569	590	1,541	382	2,609
Sep	1,077	2,919	867	2,608	831	2,608	588	1,663	378	2,580
Oct	1,060	2,943	858	2,568	822	2,564	574	1,660	382	2,584
Nov	1,063	2,995	851	2,566	820	2,564	559	1,662	381	2,581
Dec	1,071	2,923	850	2,566	807	2,561	556	1,659	392	2,671
Avg	1,067	2,732	974	2,788	774	2,547	706	2,000	438	2,606

Table 6-3 Sum of peak MW reductions for all registrations per month: 2010 through 2018

	Sum of Peak MW Reductions for all Registrations per Month								
Month	2010	2011	2012	2013	2014	2015	2016	2017	2018
Jan	183	132	110	193	446	169	139	123	142
Feb	121	89	101	119	307	336	128	83	70
Mar	115	81	72	127	369	198	120	111	71
Apr	111	80	108	133	146	143	118	54	71
May	172	98	143	192	151	161	131	169	70
Jun	209	561	954	433	483	833	121	240	105
Jul	999	561	1,631	1,088	665	1,362	1,316	936	518
Aug	794	161	952	497	358	272	249	141	581
Sep	276	84	451	530	795	816	263	140	112
Oct	118	81	242	168	214	136	150	88	69
Nov	111	86	165	155	166	127	116	81	54
Dec	114	88	98	168	155	122	147	83	11
Annual	1,202	840	1,942	1,486	1,739	1,858	1,451	1,217	758

The registered MW in the economic load response program are not a good measure of the MW available for dispatch in the energy market. Economic resources can dispatch up to the amount of MW registered in the program, but are not required to offer any MW. Table 6-3 shows the sum of peak economic MW dispatched by registration each month from January 1, 2010, through December 31, 2018. The monthly peak is the sum of each registration's monthly noncoincident peak dispatched MW and annual peak is the sum of each registration's annual noncoincident peak dispatched MW. The peak dispatched MW for all economic demand response registered resources decreased by 458 MW, 37.7 percent, from 1,217 MW in 2017 to 758 MW in 2018.[28] The peak dispatched MW in 2018, 758 MW, were 1,848 MW less than the average MW registered in 2018, 2,606 MW.

Emergency and economic demand response energy payments are uplift and not compensated by LMP revenues. Economic demand response energy costs are assigned to real-time exports from the PJM Region and real-time loads in each zone for which the load-weighted average real-time LMP for the hour during which the reduction occurred is greater than the price determined under the net benefits test for that month.[29] The zonal allocation is shown in Table 6-13.

Table 6-4 shows the total MW reductions made by participants in the economic program and the total credits paid for these reductions in 2010 through 2018. The average credits per MWh paid increased by $9.87 per MWh, 22.8 percent, from $43.27 per MWh in 2017 to $53.13 per MWh in 2018. The PJM real-time, load-weighted, average LMP was 23.4 percent higher in 2018 than in 2017, $38.24 per MWh versus $30.99 per MWh. Curtailed energy for the economic program decreased by 13,634 MWh, 21.8 percent, from 62,622 MWh in 2017 to 48,988 MWh in 2018. Total credits paid for economic DR in

27 Data for years 2010 through 2013 are available in the *2017 State of the Market Report for PJM.*

28 The total credits and MWh numbers for demand resources were calculated as of January 9, 2019 and may change as a result of continued PJM billing updates.

29 "PJM Manual 28: Operating Agreement Accounting," § 11.2.2 Economic Load Response Program, Rev. 81 (Oct. 25, 2018).

2017 decreased by $0.1 million, 3.5 percent, from $2.7 million in 2017 to $2.6 million in 2018.

Table 6-4 Credits paid to the PJM economic program participants: 2010 through 2018

	Total MWh	Total Credits	$/MWh
2010	72,757	$3,088,049	$42.44
2011	17,398	$2,052,996	$118.00
2012	144,285	$9,278,942	$64.31
2013	133,963	$8,711,873	$65.03
2014	146,301	$17,820,063	$121.80
2015	121,129	$7,983,488	$65.91
2016	81,908	$3,550,535	$43.35
2017	62,622	$2,709,335	$43.27
2018	49,185	$2,613,258	$53.13

Economic demand response resources that are dispatched by PJM in both the economic and emergency programs are paid the higher price defined in the emergency rules.[30] For example, assume a demand resource has an economic offer price of $100 per MWh and an emergency strike price of $1,800 per MWh. If this resource were scheduled to reduce in the Day-Ahead Energy Market, the demand resource would receive $100 per MWh, but if an emergency event were called during the economic dispatch, the demand resource would receive its emergency strike price of $1,800 per MWh instead. The rationale for this rule is not clear.[31] All other resources that clear in the day-ahead market are financially firm at the clearing price. Payment at a guaranteed strike price and the ability to set energy market prices at the strike price effectively grant the seller the right to exercise market power.

Figure 6-2 shows monthly economic demand response credits and MWh, from January 1, 2010 through December 31, 2018.

Figure 6-2 Economic program credits and MWh by month: 2010 through 2018

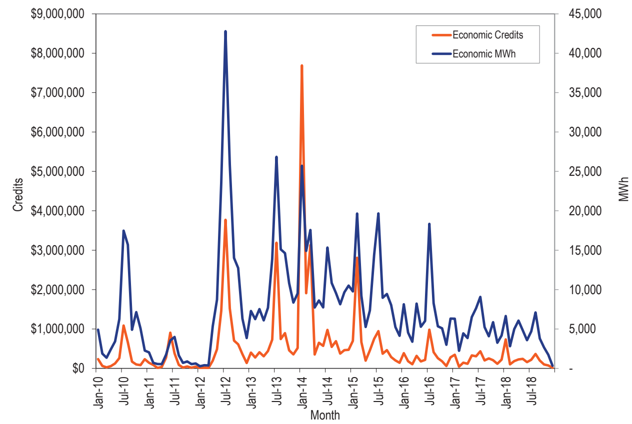


Table 6-5 shows performance for 2017 and 2018 in the economic program by control zone. Total reductions under the economic program decreased by 13,436 MWh, 21.5 percent, from 62,622 MW in 2017 to 49,185 MW in 2018. Total revenue under the economic program decreased by $0.1 million, 1.6 percent, from $2.7 million in 2017 to $2.6 million in 2018.[32]

30 PJM. "Manual 11: Energy & Ancillary Services Market Operations," § 10.4.5 Emergency and Pre-Emergency Energy Settlements, Rev. 104 (February 7, 2019).
31 FERC Order No. 831.

32 Economic demand response reductions that are submitted to PJM for payment but have not received payment are not included in Table 6-5. Payments for Economic demand response reductions are settled monthly.

Table 6-5 PJM economic program participation by zone: 2017 and 2018[33]

	Credits			MWh Reductions			Credits per MWh Reduction		
Zones	2017	2018	Percent Change	2017	2018	Percent Change	2017	2018	Percent Change
AECO	$0.00	$8,505.13	NA	0	115	NA	NA	$74.12	NA
AEP	$8.84	$3,121.17	35,194.4%	0	93	44,388.3%	$42.19	$33.47	(20.7%)
APS	$31,042.15	$53,255.11	71.6%	728	967	32.9%	$42.66	$55.05	29.0%
ATSI	$316,133.07	$948,934.08	200.2%	7,157	18,857	163.5%	$44.17	$50.32	13.9%
BGE	$133,084.25	$152,018.22	14.2%	2,503	2,692	7.6%	$53.17	$56.47	6.2%
ComEd	$193,816.15	$201,072.77	3.7%	5,861	5,407	(7.7%)	$33.07	$37.19	12.5%
DEOK	$21,122.21	$44,124.26	108.9%	159	341	114.8%	$133.21	$129.58	(2.7%)
Dominion	$513,393.00	$40,169.90	(92.2%)	7,862	199	(97.5%)	$65.30	$201.43	208.5%
DPL	$0.00	($17,507.06)	NA	516	(183)	(135.4%)	NA	$95.87	NA
JCPL	$85,579.20	$250,025.99	192.2%	1,242	3,612	190.9%	$68.92	$69.22	0.4%
Met-Ed	$12,250.98	$60,930.15	397.3%	287	1,271	342.2%	$42.62	$47.93	12.5%
OVEC	NA	NA	NA	NA	NA	NA	NA	NA	NA
PECO	$94,790.76	$59,241.54	(37.5%)	589	947	60.9%	$161.00	$62.54	(61.2%)
PENELEC	$388,348.85	$201,208.18	(48.2%)	11,166	3,745	(66.5%)	$34.78	$53.73	54.5%
Pepco	$0.00	($4,922.52)	NA	1,095	(161)	(114.7%)	NA	$30.54	NA
PPL	$81,928.94	$129,104.18	57.6%	1,890	1,178	(37.6%)	$43.36	$109.56	152.7%
PSEG	$773,173.99	$483,977.02	(37.4%)	21,568	10,103	(53.2%)	$35.85	$47.90	33.6%
Total	$2,644,672.38	$2,601,631.83	(1.6%)	62,622	49,185	(21.5%)	$42.23	$52.89	25.2%

Table 6-6 shows total settlements submitted for 2010 through 2018. A settlement is counted for every day on which a registration is dispatched in the economic program.

Table 6-6 Settlements submitted in the economic program: 2010 through 2018

	2010	2011	2012	2013	2014	2015	2016	2017	2018
Number of Settlements	3,781	732	5,835	2,846	3,014	2,173	1,958	1,884	1,524

Table 6-7 shows the number of CSPs, and the number of participants in their portfolios, submitting settlements by year for 2010 through 2018. The number of active participants decreased by 13, 18.1 percent, from 72 in 2017 to 59 in 2018. All participants must be registered through a CSP.

Table 6-7 Participants and CSPs submitting settlements in the economic program by year: 2010 through 2018

	2010	2011	2012	2013	2014	2015	2016	2017	2018
Active CSPs	16	15	22	20	18	18	12	13	14
Active Participants	258	203	428	276	165	116	58	72	59

The ownership of economic demand response resources was highly concentrated in 2017 and 2018.[34] Table 6-8 shows the average hourly HHI for each month and the average hourly HHI for January 1, 2017 through December 31, 2018. Table 6-8 also lists the share of reductions provided by, and the share of credits claimed by the four largest companies in each year. In 2018, 84.8 percent of all economic DR reductions and 83.3 percent of economic DR revenue were attributable to the four largest companies. The HHI for economic demand response remained the same at 7590 for 2017 and 2018.

33 Negative reduction values and negative credits occur when resources clear the day-ahead market but do not respond in real time.
34 All HHI calculations in this section are at the parent company level. Parent companies may own one CSP or multiple CSPs.

Table 6-8 HHI and market concentration in the economic program: January 2017 through December 2018[35]

	HHI			Top Four Companies Share of Reduction			Top Four Companies Share of Credit		
Month	2017	2018	Percent Change	2017	2018	Change in Percent	2017	2018	Change in Percent
Jan	8952	6572	(26.6%)	99.7%	92.2%	7.5%	99.6%	89.6%	10.0%
Feb	9263	8308	(10.3%)	100.0%	99.2%	0.8%	100.0%	99.1%	0.9%
Mar	8170	7495	(8.3%)	99.4%	96.0%	3.4%	98.1%	95.7%	2.4%
Apr	6099	6827	11.9%	100.0%	97.3%	2.7%	100.0%	97.2%	2.8%
May	7046	6685	(5.1%)	97.5%	98.3%	(0.8%)	92.7%	97.9%	(5.2%)
Jun	7702	8375	8.7%	91.6%	97.4%	(5.8%)	88.6%	96.2%	(7.5%)
Jul	7793	8256	5.9%	87.5%	90.2%	(2.7%)	77.6%	82.7%	(5.1%)
Aug	8006	7588	(5.2%)	99.5%	90.0%	9.4%	99.5%	87.1%	12.4%
Sep	7877	9306	18.1%	94.9%	97.4%	(2.4%)	87.8%	97.2%	(9.4%)
Oct	6467	6805	5.2%	97.6%	95.6%	2.0%	97.8%	93.9%	4.0%
Nov	7334	7038	(4.0%)	96.9%	91.0%	6.0%	96.4%	91.1%	5.3%
Dec	7493	8082	7.9%	94.3%			89.0%		
Total	7590	7540	(0.7%)	87.2%	84.8%	(2.4%)	85.9%	83.3%	(2.6%)

Table 6-9 shows average MWh reductions and credits by hour for 2017 and 2018. In 2017, 93.5 percent of reductions and 88.5 percent of credits occurred in hours ending 0900 to 2100, and in 2018, 92.6 percent of reductions and 86.4 percent of credits occurred in hours ending 0900 to 2100.

Table 6-9 Hourly frequency distribution of economic program MWh reductions and credits: 2017 and 2018

	MWh Reductions			Program Credits		
Hour Ending (EPT)	2017	2018	Percent Change	2017	2018	Percent Change
1 through 6	641	1,277	99%	$39,271	$92,842	136%
7	508	1,071	111%	$29,612	$69,474	135%
8	1,494	1,751	17%	$67,999	$109,413	61%
9	2,632	2,344	(11%)	$94,398	$115,818	23%
10	3,222	2,588	(20%)	$108,327	$117,751	9%
11	3,574	2,783	(22%)	$122,123	$129,746	6%
12	3,825	2,973	(22%)	$132,691	$134,577	1%
13	4,071	2,937	(28%)	$152,121	$132,678	(13%)
14	4,916	3,709	(25%)	$197,165	$168,997	(14%)
15	5,513	3,803	(31%)	$244,502	$186,864	(24%)
16	5,832	3,937	(32%)	$254,269	$219,741	(14%)
17	6,028	4,631	(23%)	$314,950	$288,804	(8%)
18	6,181	4,437	(28%)	$310,368	$258,453	(17%)
19	5,227	3,441	(34%)	$221,040	$197,499	(11%)
20	4,403	3,213	(27%)	$173,964	$165,222	(5%)
21	3,134	2,724	(13%)	$122,890	$141,714	15%
22	856	1,026	20%	$43,103	$54,936	27%
23 through 24	564	541	(4%)	$15,878	$28,730	81%
Total	62,622	49,185	(21%)	$2,644,672	$2,613,258	(1%)

Table 6-10 shows the distribution of economic program MWh reductions and credits by ranges of real-time zonal, load-weighted, average LMP in 2017 and 2018. In 2018, 3.2 percent of MWh reductions and 13.3 percent of program credits occurred during hours when the applicable zonal LMP was higher than $175 per MWh.

Table 6-10 Frequency distribution of economic program zonal, load-weighted, average LMP (By hours): 2017 and 2018

	MWh Reductions			Program Credits		
LMP	2017	2018	Percent Change	2017	2018	Percent Change
$0 to $25	5,145	4,359	(15%)	$76,457	$79,302	4%
$25 to $50	42,147	29,815	(29%)	$1,323,544	$1,095,204	(17%)
$50 to $75	9,148	6,796	(26%)	$530,695	$406,223	(23%)
$75 to $100	2,925	3,509	20%	$258,890	$295,055	14%
$100 to $125	1,382	1,475	7%	$151,066	$161,014	7%
$125 to $150	942	1,070	14%	$125,612	$142,849	14%
$150 to $175	593	566	(5%)	$98,529	$85,778	(13%)
> $175	333	1,579	375%	$79,839	$347,736	336%
Total	62,614	49,170	(21%)	$2,644,632	$2,613,159	(1%)

Following Order No. 745, all ISO/RTOs are required to calculate an NBT threshold price each month above which the net benefits of DR are deemed to exceed the cost to load. PJM calculates the NBT price threshold by first taking the generation offers from the same month of the previous year. For example, the NBT price calculation for February 2017 was calculated using generation offers from February 2016. PJM then adjusts these offers to account for changes in fuel prices and uses these adjusted offers to create an average monthly supply curve. PJM estimates a function that best fits this supply curve and then finds the point on this curve where the elasticity is equal to one.[36] The price at this point is the NBT threshold price.

35 December 2018 reduction and credit share percent is redacted based on confidentiality rules.

36 "PJM Manual 11: Energy & Ancillary Services Market Operations," §10.3.1 Net Benefits Test to determine Net Benefits Threshold, Rev. 102 (Jan. 22, 2019).

The NBT test is a crude tool that is not based in market logic. The NBT threshold price is a monthly estimate calculated from a monthly supply curve that does not incorporate real-time or day-ahead prices. In addition, it is a single threshold price used to trigger payments to economic demand response resources throughout the entire RTO, regardless of their location and regardless of locational prices.

The necessity for the NBT test is an illustration of the illogical approach to demand side compensation embodied in paying full LMP to demand resources. The benefit of demand side resources is not that they suppress market prices, but that customers can choose not to consume at the current price of power, that individual customers benefit from their choices and that the choices of all customers are reflected in market prices. If customers face the market price, customers should have the ability to not purchase power and the market impact of that choice does not require a test for appropriateness.

When the zonal LMP is above the NBT threshold price, economic demand response resources that reduce their power consumption are paid the full zonal LMP. When the zonal LMP is below the NBT threshold price, economic demand response resources are not paid for any load reductions.

Table 6-11 shows the NBT threshold price from April 1, 2012, when Order No. 745 was implemented in PJM, through December 31, 2018.

Table 6-11 Net benefits test threshold prices: April 2012 through December 2018

	Net Benefits Test Threshold Price ($/MWh)						
Month	2012	2013	2014	2015	2016	2017	2018
Jan		$25.72	$29.51	$29.63	$23.67	$32.60	$26.27
Feb		$26.27	$30.44	$26.52	$26.71	$31.57	$24.65
Mar		$25.60	$34.93	$24.99	$22.10	$30.56	$25.50
Apr	$25.89	$26.96	$32.59	$24.92	$19.93	$30.45	$25.56
May	$23.46	$27.73	$32.08	$23.79	$20.69	$29.77	$25.52
Jun	$23.86	$28.44	$31.62	$23.80	$20.62	$27.14	$23.59
Jul	$22.99	$29.42	$31.62	$23.03	$20.73	$24.42	$23.57
Aug	$24.47	$28.58	$29.85	$23.17	$23.24	$22.75	$23.53
Sep	$24.93	$28.80	$29.83	$21.69	$24.70	$21.51	$22.23
Oct	$25.96	$29.13	$30.20	$21.48	$26.50	$21.70	$23.84
Nov	$25.63	$31.63	$29.17	$22.28	$29.27	$26.41	$23.89
Dec	$25.97	$28.82	$29.01	$22.31	$29.71	$29.16	$26.35
Average	$24.80	$28.09	$30.91	$23.97	$23.99	$27.34	$24.54

Table 6-12 shows the number of hours that at least one zone in PJM had day-ahead LMP or real-time LMP higher than the NBT threshold price. In 2018, the highest zonal LMP in PJM was higher than the NBT threshold price 7,398 hours out of 8,760 hours, or 84.5 percent of all hours. Reductions occurred in 4,185 hours, 56.6 percent, of those 7,398 hours in 2018. The last three columns illustrate how often economic demand response activity occurred when LMPs exceeded NBT threshold prices for January 1, 2017 through December 31, 2018. There are no economic payments when demand response occurs and zonal LMP is below the NBT threshold. Demand response reductions occurred in 5.1 percent (200 hours) of the hours in which LMP was below the NBT threshold price in 2017, and none of the hours in which LMP was below the NBT threshold price in 2018.

Table 6-12 Hours with price higher than NBT and DR occurrences in those hours: 2017 and 2018

	Number of Hours		Number of Hours with LMP Higher than NBT			Percent of NBT Hours with DR		
Month	2017	2018	2017	2018	Percent Change	2017	2018	Percent Change
Jan	744	744	388	665	71.4%	63.4%	62.9%	(0.5%)
Feb	672	672	414	485	17.1%	37.7%	44.7%	7.1%
Mar	743	743	484	713	47.3%	64.3%	58.3%	(5.9%)
Apr	720	720	407	663	62.9%	72.7%	73.8%	1.0%
May	744	744	445	611	37.3%	76.0%	62.7%	(13.3%)
Jun	720	720	421	503	19.5%	67.5%	64.0%	(3.4%)
Jul	744	744	546	549	0.5%	67.2%	74.0%	6.7%
Aug	744	744	573	560	(2.3%)	55.7%	72.5%	16.8%
Sep	720	720	641	643	0.3%	52.4%	64.2%	11.8%
Oct	744	744	742	699	(5.8%)	61.2%	50.9%	(10.3%)
Nov	721	721	499	702	40.7%	59.1%	41.3%	(17.8%)
Dec	744	744	509	605	18.9%	60.1%	11.4%	(48.7%)
Total	8,760	8,760	6,069	7,398	21.9%	61.1%	56.6%	(4.5%)

Economic DR revenues are paid by real-time loads and real-time scheduled exports as an uplift charge. Table 6-13 shows the sum of real-time DR charges and day-ahead DR charges paid in each zone and paid by exports. Real-time loads in AEP and Dominion paid the highest DR charges in 2018.[37]

37 In December 2018, PJM integrated the Ohio Valley Electric Corporation (OVEC.).

Table 6-13 Zonal DR charge: 2018

Zone	January	February	March	April	May	June	July	August	September	October	November	December	Total
AECO	$8,097	$1,186	$1,285	$2,112	$1,791	$1,988	$3,202	$5,949	$2,484	$1,077	$761	$153	$30,085
AEP	$120,561	$15,321	$33,257	$38,747	$42,369	$24,805	$31,756	$53,271	$30,850	$15,355	$11,094	$2,056	$419,441
APS	$48,552	$6,552	$13,514	$15,101	$15,776	$9,097	$12,164	$20,839	$11,664	$5,721	$4,292	$820	$164,091
ATSI	$57,105	$8,625	$17,573	$20,367	$22,996	$13,165	$17,540	$29,931	$16,780	$8,792	$5,738	$1,053	$219,663
BGE	$31,568	$4,497	$8,721	$9,385	$10,488	$6,459	$8,874	$15,317	$7,949	$3,842	$2,545	$498	$110,144
ComEd	$62,782	$9,476	$15,824	$23,196	$26,116	$18,971	$26,737	$33,712	$23,113	$10,657	$8,013	$1,445	$260,040
DAY	$15,727	$2,218	$4,647	$5,567	$6,294	$3,470	$4,414	$7,682	$4,387	$2,228	$1,606	$299	$58,540
DEOK	$23,915	$2,899	$6,629	$7,909	$9,664	$5,775	$7,299	$12,155	$7,021	$3,182	$2,212	$402	$89,063
Dominion	$103,016	$12,383	$26,495	$27,738	$34,552	$20,813	$26,832	$46,452	$24,872	$12,233	$8,114	$1,600	$345,100
DPL	$19,093	$2,543	$3,112	$4,703	$3,678	$3,444	$5,191	$9,415	$4,308	$2,089	$1,468	$295	$59,340
DLCO	$11,456	$1,571	$3,335	$4,121	$4,939	$2,802	$3,847	$6,598	$3,638	$1,727	$1,127	$208	$45,370
EKPC	$14,563	$1,567	$3,053	$3,422	$3,886	$2,498	$3,281	$5,403	$3,039	$1,385	$1,185	$217	$43,498
JCPL	$19,114	$2,897	$3,073	$5,315	$4,892	$4,684	$7,338	$13,779	$5,471	$2,528	$1,781	$353	$71,226
Met-Ed	$14,390	$1,984	$2,647	$3,918	$3,108	$2,535	$3,993	$7,257	$3,277	$1,715	$1,305	$259	$46,387
OVEC												$1	$1
PECO	$36,605	$5,041	$5,544	$10,159	$7,781	$7,123	$11,119	$20,216	$8,804	$4,321	$3,230	$630	$120,573
PENELEC	$15,500	$2,438	$4,255	$5,383	$4,952	$2,952	$4,040	$7,090	$3,884	$2,182	$1,552	$284	$54,513
Pepco	$29,228	$3,750	$8,347	$8,881	$10,702	$6,275	$8,499	$14,544	$7,684	$3,629	$2,461	$462	$104,464
PPL	$39,796	$5,130	$5,853	$10,477	$7,263	$6,165	$9,733	$16,792	$8,046	$4,482	$3,415	$629	$117,781
PSEG	$35,936	$5,695	$6,059	$10,531	$9,467	$8,316	$12,773	$23,427	$10,130	$4,988	$3,479	$667	$131,468
RECO	$1,144	$184	$208	$362	$390	$340	$506	$933	$389	$173	$117	$22	$4,769
Exports	$25,969	$4,832	$9,278	$10,340	$9,805	$5,875	$7,593	$14,263	$9,585	$5,852	$2,432	$664	$106,488
Total	$734,117	$100,789	$182,709	$227,734	$240,911	$157,552	$216,730	$365,025	$197,374	$98,159	$67,927	$13,018	$2,602,044

Table 6-14 shows the total zonal DR charge per MWh of real-time load and exports in 2018. On a dollar per MWh basis, real-time load and exports in ComEd paid the highest charges for economic demand response in 2018. The highest average zonal monthly per MWh charges for economic demand response occurred in January, when ComEd, DEOK and EKPC paid an average of $0.014/MWh.

Table 6-14 Zonal DR charge per MWh of load and exports: 2018

Zone	January	February	March	April	May	June	July	August	September	October	November	December	Zonal Average
AECO	$0.013	$0.003	$0.004	$0.003	$0.002	$0.002	$0.003	$0.005	$0.003	$0.001	$0.001	$0.000	$0.003
AEP	$0.013	$0.003	$0.004	$0.004	$0.004	$0.002	$0.003	$0.005	$0.003	$0.002	$0.001	$0.000	$0.004
APS	$0.013	$0.003	$0.004	$0.004	$0.004	$0.002	$0.003	$0.005	$0.003	$0.001	$0.001	$0.000	$0.004
ATSI	$0.013	$0.003	$0.004	$0.004	$0.004	$0.002	$0.003	$0.005	$0.003	$0.002	$0.001	$0.000	$0.004
BGE	$0.013	$0.003	$0.003	$0.004	$0.004	$0.002	$0.003	$0.005	$0.003	$0.002	$0.001	$0.000	$0.004
ComEd	$0.014	$0.004	$0.004	$0.003	$0.003	$0.002	$0.003	$0.003	$0.003	$0.001	$0.001	$0.000	$0.004
DAY	$0.013	$0.003	$0.004	$0.004	$0.004	$0.002	$0.003	$0.005	$0.003	$0.002	$0.001	$0.000	$0.004
DEOK	$0.014	$0.003	$0.004	$0.004	$0.004	$0.002	$0.003	$0.005	$0.003	$0.001	$0.001	$0.000	$0.004
Dominion	$0.013	$0.003	$0.003	$0.004	$0.004	$0.002	$0.003	$0.005	$0.003	$0.002	$0.001	$0.000	$0.004
DPL	$0.013	$0.003	$0.004	$0.004	$0.003	$0.002	$0.003	$0.005	$0.003	$0.002	$0.001	$0.000	$0.004
DLCO	$0.013	$0.003	$0.004	$0.004	$0.004	$0.002	$0.003	$0.005	$0.003	$0.002	$0.001	$0.000	$0.004
EKPC	$0.014	$0.003	$0.004	$0.004	$0.004	$0.002	$0.003	$0.005	$0.003	$0.001	$0.001	$0.000	$0.004
JCPL	$0.013	$0.003	$0.004	$0.003	$0.003	$0.002	$0.003	$0.005	$0.003	$0.002	$0.001	$0.000	$0.004
Met-Ed	$0.013	$0.003	$0.004	$0.003	$0.003	$0.002	$0.003	$0.005	$0.003	$0.001	$0.001	$0.000	$0.003
OVEC												$0.000	$0.000
PECO	$0.013	$0.003	$0.004	$0.004	$0.003	$0.002	$0.003	$0.005	$0.003	$0.001	$0.001	$0.000	$0.003
PENELEC	$0.013	$0.003	$0.004	$0.004	$0.004	$0.002	$0.003	$0.005	$0.003	$0.002	$0.001	$0.000	$0.004
Pepco	$0.013	$0.003	$0.003	$0.004	$0.004	$0.002	$0.003	$0.005	$0.003	$0.002	$0.001	$0.000	$0.004
PPL	$0.013	$0.003	$0.004	$0.003	$0.002	$0.002	$0.003	$0.005	$0.003	$0.001	$0.001	$0.000	$0.003
PSEG	$0.013	$0.003	$0.004	$0.003	$0.003	$0.002	$0.003	$0.005	$0.003	$0.001	$0.001	$0.000	$0.003
RECO	$0.013	$0.003	$0.004	$0.004	$0.003	$0.002	$0.003	$0.006	$0.003	$0.002	$0.001	$0.000	$0.004
Exports	$0.011	$0.002	$0.003	$0.005	$0.004	$0.002	$0.002	$0.004	$0.003	$0.002	$0.001	$0.000	$0.003
Monthly Average	$0.013	$0.003	$0.004	$0.004	$0.004	$0.002	$0.003	$0.005	$0.003	$0.002	$0.001	$0.000	$0.004

Table 6-15 shows the monthly day-ahead and real-time DR charges and the per MWh DR charges for 2017 and 2018. The day-ahead DR charges increased by $0.05 million, 5.3 percent, from $0.87 million in 2017 to $0.92 million in 2018. The real-time DR charges decreased $0.1 million, 4.4 percent, from $1.8 million in 2017 to $1.7 million in 2018.

Table 6-15 Monthly day-ahead and real-time economic DR charge: 2017 through 2018

	Day-ahead DR Charge			Real-time DR Charge		
Month	2017	2018	Percent Change	2017	2018	Percent Change
Jan	$35,134	$319,726	810.0%	$311,498	$414,391	33.0%
Feb	$25,562	$23,206	(9.2%)	$16,797	$77,584	361.9%
Mar	$70,093	$58,999	(15.8%)	$75,293	$125,482	66.7%
Apr	$87,514	$85,677	(2.1%)	$27,455	$142,057	417.4%
May	$75,756	$97,313	28.5%	$251,622	$143,598	(42.9%)
Jun	$132,225	$56,538	(57.2%)	$172,812	$101,014	(41.5%)
Jul	$100,525	$63,540	(36.8%)	$269,488	$153,191	(43.2%)
Aug	$64,713	$70,708	9.3%	$135,343	$294,316	117.5%
Sep	$79,924	$44,648	(44.1%)	$171,172	$152,727	(10.8%)
Oct	$74,161	$57,842	(22.0%)	$131,587	$40,317	(69.4%)
Nov	$23,472	$32,131	36.9%	$91,519	$41,994	(54.1%)
Dec	$104,711	$9,890	(90.6%)	$116,295	$6,369	(94.5%)
Total	$873,791	$920,219	5.3%	$1,770,882	$1,693,040	(4.4%)

Emergency and Pre-Emergency Programs

The emergency and pre-emergency load response programs consist of the limited, extended summer, annual and capacity performance demand response products. Full implementation of the Capacity Performance design in the 2020/2021 Delivery Year will require all emergency or pre-emergency demand resource to be registered as an annual capacity resource. Summer period demand response resources are allowed to aggregate with winter period capacity resources to fulfill the annual requirement of the CP design.[38] With the implementation of Capacity Performance, a performance assessment interval (PAI) occurs when emergency or pre-emergency is dispatched. PJM effectively eliminated the difference between pre-emergency and emergency by making both trigger a PAI. To participate as an emergency or pre-emergency demand resource, the CSP must clear MW in an RPM auction. Emergency and pre-emergency resources receive capacity revenue from the capacity market and also receive energy revenue at a predefined strike price from the energy market for reductions during a PJM initiated emergency or pre-emergency event. The rules applied to demand resources in the current market design do not treat demand resources in a manner comparable to generation capacity resources, even though demand resources are sold in the same capacity market, are treated as a substitute for other capacity resources and displace other capacity resources in RPM auctions.

The MMU recommends that if demand resources remain on the supply side of the capacity market, a daily must offer requirement in the Day-Ahead Energy Market apply to demand resources, comparable to the rule applicable to generation capacity resources. This will help to ensure comparability and consistency for demand resources.

The MMU recommends that the option to specify a minimum dispatch price under the Emergency and Pre-Emergency Program Full option be eliminated and that participating resources receive the hourly real-time LMP less any generation component of their retail rate.[39]

The ownership of demand resources was moderately concentrated based on committed MW in the capacity market in the 2017/2018 Delivery Year. The HHI for demand resources was 1433 for the 2017/2018 Delivery Year and 1922 for the 2018/2019 Delivery Year. In the 2017/2018 Delivery Year, the four largest companies contributed 69.6 percent of all registered demand resources. In the 2018/2019 Delivery Year, the four largest companies contributed 77.9 percent of all registered demand resources.

Table 6-16 shows the HHI value for LDAs by delivery year. The HHI values are calculated by the cleared UCAP MW in each delivery year for demand resources. The closed loop interfaces created for the purpose of allowing emergency DR to set price are located in the RTO, MAAC, EMAAC, SWMAAC, DPL-SOUTH, ATSI, ATSI-CLEVELAND and BGE LDAs.

38 Summer period demand response has the same obligations as extended summer demand response. It must be available for June through October and the following May between 10:00AM and 10:00PM. See PJM OATT RAA Article 1.

39 See "Complaint and Motion to Consolidate of the Independent Market Monitor for PJM," Docket No. EL14-20-000 (January 28, 2014); "Comments of the Independent Market Monitor for PJM," Docket No. ER15-852-000 (February 13, 2015).

Table 6-16 HHI value for LDAs by delivery year: 2017/2018 and 2018/2019 Delivery Years[40]

Delivery Year	LDA	UCAP MW	HHI Value	HHI Concentration
2017/2018	RTO	4,018.0	2593	High
	MAAC	655.7	1914	High
	EMAAC	1,057.3	2093	High
	DPL-SOUTH	86.3	3145	High
	PSEG	236.9	1409	Moderate
	PS-NORTH	151.5	2043	High
	PEPCO	608.4	3726	High
	ATSI	720.8	3615	High
	ATSI-CLEVELAND	282.4	4927	High
	COMED	1,470.8	3353	High
	BGE	790.7	5309	High
	PPL	650.5	2167	High
2018/2019	RTO	4,044.7	2199	High
	MAAC	712.1	2144	High
	EMAAC	1,205.6	2,028	High
	PSEG	249.6	2,298	High
	PS-NORTH	132.6	3,085	High
	PEPCO	523.1	5,027	High
	ATSI	609.4	3,413	High
	ATSI-CLEVELAND	267.6	3,514	High
	COMED	1,876.7	3,183	High
	BGE	660.0	5,424	High
	PPL	716.2	1,862	High

Table 6-17 shows the demand response cleared UCAP MW by delivery year. Total demand response cleared in PJM decreased by 594.9 MW, or 5.0 percent, from 11,870.7 MW in the 2017/2018 Delivery Year to 11,275.8 MW in the 2018/2019 Delivery Year. The DR percent of capacity decreased by 0.3 percent, from 6.1 percent in the 2017/2018 Delivery Year to 5.8 percent in the 2018/2019 Delivery Year.

Table 6-17 Demand response cleared MW UCAP for PJM: 2011/2012 through 2017/2018 Delivery Years

Delivery Year	DR Cleared MW UCAP	DR Percent of Capacity MW UCAP
2011/2012	1,826.6	1.4%
2012/2013	8,740.9	6.2%
2013/2014	10,779.6	6.7%
2014/2015	14,943.0	9.3%
2015/2016	15,453.7	8.9%
2016/2017	13,265.3	6.6%
2017/2018	11,870.7	6.1%
2018/2019	11,275.8	5.8%

Table 6-18 shows zonal monthly capacity market revenue to demand resources for 2018. Capacity market revenue increased in 2018 by $91.8 million, 18.5 percent, from $495.2 million in 2017 to $587.0 million in 2018. Higher demand resource revenues were in part a result of higher capacity market prices in 2018. The capacity revenue in 2017 is from 2016/2017 and 2017/2018 RPM auction clearing prices and the capacity revenue in 2018 is from 2017/2018 and 2018/2019 RPM auction clearing prices. Average capacity market prices increased $34.39 per MW-day from $141.19 in the 2017/2018 Delivery Year to $175.58 in the 2018/2019 Delivery Year, a 24.4 percent increase.[41]

40 The RTO LDA refers to the rest of RTO.

41 See the *2018 State of the Market Report for PJM*, Section 7: Net Revenue, Table 7-6.

Table 6-18 Zonal monthly capacity revenue: 2018

Zone	January	February	March	April	May	June	July	August	September	October	November	December	Total
AECO	$490,121	$442,690	$490,121	$474,310	$490,121	$1,028,760	$1,063,052	$1,063,052	$1,028,760	$1,063,052	$1,028,760	$1,063,052	$9,725,847
AEP, EKPC	$6,277,982	$5,670,436	$6,277,982	$6,075,467	$6,277,982	$7,126,198	$7,363,738	$7,363,738	$7,126,198	$7,363,738	$7,126,198	$7,363,738	$81,413,392
APS	$3,635,631	$3,283,796	$3,635,631	$3,518,353	$3,635,631	$4,488,613	$4,638,234	$4,638,234	$4,488,613	$4,638,234	$4,488,613	$4,638,234	$49,727,818
ATSI	$4,068,474	$3,674,751	$4,068,474	$3,937,233	$4,068,474	$4,117,257	$4,254,499	$4,254,499	$4,117,257	$4,254,499	$4,117,257	$4,254,499	$49,187,171
BGE	$2,978,415	$2,690,181	$2,978,415	$2,882,337	$2,978,415	$1,424,334	$1,471,812	$1,471,812	$1,424,334	$1,471,812	$1,424,334	$1,471,812	$24,668,012
ComEd	$5,931,017	$5,357,047	$5,931,017	$5,739,694	$5,931,017	$11,384,156	$11,763,628	$11,763,628	$11,384,156	$11,763,628	$11,384,156	$11,763,628	$110,096,771
DAY	$757,213	$683,934	$757,213	$732,787	$757,213	$1,047,740	$1,082,665	$1,082,665	$1,047,740	$1,082,665	$1,047,740	$1,082,665	$11,162,240
DEOK	$680,554	$614,694	$680,554	$658,601	$680,554	$963,997	$996,130	$996,130	$963,997	$996,130	$963,997	$996,130	$10,191,470
DLCO	$4,444,838	$4,014,692	$4,444,838	$4,301,456	$4,444,838	$3,717,864	$3,841,793	$3,841,793	$3,717,864	$3,841,793	$3,717,864	$3,841,793	$48,171,428
Dominion	$1,493,172	$1,348,671	$1,493,172	$1,445,005	$1,493,172	$2,671,780	$2,760,840	$2,760,840	$2,671,780	$2,760,840	$2,671,780	$2,760,840	$26,331,892
DPL	$664,561	$600,248	$664,561	$643,123	$664,561	$1,190,255	$1,229,930	$1,229,930	$1,190,254	$1,229,930	$1,190,255	$1,229,930	$11,727,536
JCPL	$616,455	$556,798	$616,455	$596,570	$616,455	$1,281,410	$1,324,124	$1,324,124	$1,281,410	$1,324,124	$1,281,410	$1,324,124	$12,143,461
Met-Ed	$1,122,182	$1,013,583	$1,122,182	$1,085,982	$1,122,182	$1,478,427	$1,527,708	$1,527,708	$1,478,427	$1,527,708	$1,478,427	$1,527,708	$16,012,226
OVEC	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
PECO	$1,860,312	$1,680,282	$1,860,312	$1,800,302	$1,860,312	$3,234,300	$3,342,110	$3,342,110	$3,234,300	$3,342,110	$3,234,300	$3,342,110	$32,132,862
PENELEC	$1,330,187	$1,201,460	$1,330,187	$1,287,278	$1,330,187	$1,753,015	$1,811,449	$1,811,449	$1,753,015	$1,811,449	$1,753,015	$1,811,449	$18,984,142
Pepco	$2,320,851	$2,096,252	$2,320,851	$2,245,985	$2,320,851	$780,853	$806,881	$806,881	$780,853	$806,881	$780,853	$806,881	$16,874,873
PPL	$2,491,224	$2,250,138	$2,491,224	$2,410,862	$2,491,224	$2,240,289	$2,314,965	$2,314,965	$2,240,289	$2,314,965	$2,240,289	$2,314,965	$28,115,402
PSEG	$2,576,169	$2,326,862	$2,576,169	$2,493,066	$2,576,169	$2,440,539	$2,521,890	$2,521,890	$2,440,539	$2,521,890	$2,440,539	$2,521,890	$29,957,610
RECO	$12,475	$11,267	$12,475	$12,072	$12,475	$47,392	$48,971	$48,971	$47,392	$48,971	$47,392	$48,971	$398,824
Total	$43,751,832	$39,517,784	$43,751,832	$42,340,483	$43,751,832	$52,417,179	$54,164,419	$54,164,419	$52,417,179	$54,164,419	$52,417,179	$54,164,419	$587,022,976

Table 6-19 shows the amount of energy efficiency (EE) resources in PJM on June 1 for the 2012/2013 through 2018/2019 delivery years. EE resources may participate in PJM without restrictions imposed by a state unless the Commission authorizes a state to impose restrictions.[42] Only Kentucky has been authorized by the Commission.[43] Energy efficiency resources are offered in the PJM Capacity Market. The total MW of energy efficiency resources committed increased by 20.2 percent from 2,117.9 MW in the 2017/2018 Delivery Year to 2,545.1 MW in the 2018/2019 Delivery Year.[44]

Table 6-19 Energy efficiency resources (MW): June 1, 2012 to June 1, 2018

	UCAP (MW) RPM Commitments
01-Jun-12	631.2
01-Jun-13	1,024.8
01-Jun-14	1,282.4
01-Jun-15	1,525.5
01-Jun-16	1,784.3
01-Jun-17	2,117.9
01-Jun-18	2,545.1

Figure 6-3 shows the amount of installed EE MW in PJM by technology for the 2017/2018 and 2018/2019 Delivery Years. An installed EE resource may participate as a capacity resource for up to a maximum of four consecutive delivery years.[45] The lighting category consists of more efficient lighting technology installed, HVAC consists of more efficient HVAC technology installed, new construction consists of more efficient equipment than the industry average for individual components, appliances consists of more efficient appliances and prescriptive consists of more efficient equipment procured by an incentive program for lighting, HVAC or appliances. Prescriptive energy efficiency MW have an assumed savings calculated by an expected installation rate dependent on units sold and the difference between the current average electricity usage of what is being replaced and the new product. For example, if 100 lights are sold, an expected installation rate could be that 95 are installed and replacing a light that consumes more electricity. Instead of measuring each light replaced, the EE provider takes the difference between the industry average and the new light. Prescriptive energy efficiency MW comprise 85.8 percent of all energy efficiency MW in the 2017/2018 Delivery Year and 84.5 percent in the 2018/2019 Delivery Year. The measurement and verification method for prescriptive energy efficiency projects relies on unverified assumptions and is too imprecise to rely on as a source of capacity comparable to capacity from a power plant.

All EE resources must submit pre and post installation M&V plans that include the variables that affect the project's electrical demand, baseline consumption, post installation consumption, and specifications of the equipment or types of equipment used in the project.

42 *See* 161 FERC ¶ 61,245 at P 57 (2017); 107 FERC ¶ 61,272 at P 8 (2008).

43 The Commission made an exception for Kentucky when it determined that RERRAs must obtain FERC approval prior to excluding EE, explaining that "the Commission accepted such condition at the time the Kentucky Commission approved the integration of Kentucky Power into PJM." 161 FERC ¶ 61,245 at P 67.

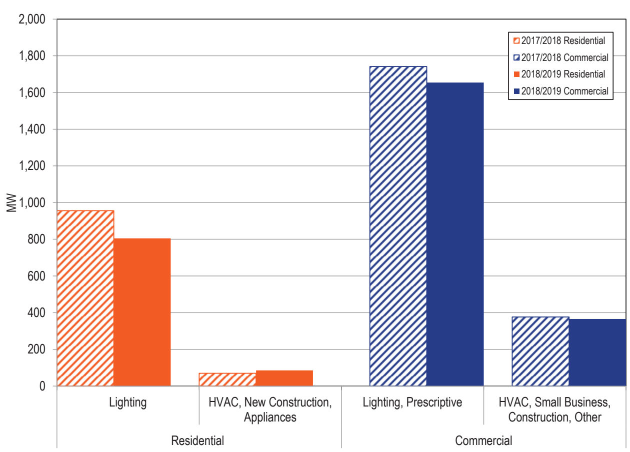
44 See the *2018 State of the Market Report for PJM*, Vol. 2, Section 5: Capacity Market, Table 5-13.

45 PJM. "Manual 18: Capacity Market," § 4.4 Energy Efficiency Resources, Rev. 41 (Jan. 1, 2019).

The nonprescriptive measurement and verification methods do not use full metering but rely on samples and assumptions and only for limited periods.[46] The nominated EE value is the expected average demand reduction during: the peak hours ending 15:00 EPT through 18:00 EPT for June 1 through August 31; and the peak hours ending 8:00 EPT through 9:00 EPT and 19:00 EPT through 20:00 EPT for all days between January 1 and February 28, of the relevant delivery year.[47] The calculated MW are offered in PJM's Capacity Market as EE. The installed EE resources for the 2017/2018 Delivery Year include any installed EE resource between June 1, 2013 and May 31, 2017, and installed EE resources for the 2018/2019 Delivery Year include any installed EE resources between June 1, 2014 and May 31, 2018.

The MMU recommends that energy efficiency MW not be included in the PJM capacity market. The measurement and verification protocols for energy efficiency are too imprecise to rely on as a source of capacity. Energy efficiency measures reduce energy usage and capacity usage directly. The reduced market payments are the appropriate compensation. PJM should ensure that the impact of EE measures on the load forecast is incorporated immediately rather than with the existing lag.

Figure 6-3 Installed energy efficiency MW by type: 2017/2018 and 2018/2019 Delivery Years



FERC accepted PJM's proposed 30 minute lead time as a phased in approach on May 9, 2014, effective on June 1, 2015.[48] The quick lead time demand response was defined after demand resources cleared in the RPM base residual auctions for the 2014/2015, 2015/2016, 2016/2017 and 2017/2018 delivery years. PJM submitted a filing on October 20, 2014, to allow DR that is unable to respond within 30 minutes to exit the market without penalty before the mandatory 30 minute lead time with the 2015/2016 Delivery Year.[49] The quick lead time is the default lead time starting June 1, 2015, unless a CSP submits an exception request for 60 or 120 minute notification time due to a physical constraint.[50] The exception requests must clearly state why the resource is unable to respond within 30 minutes based on the defined reasons for exception listed in Manual 18. Once a location is granted a longer lead time, the resource does not need to resubmit for a longer lead time each delivery year. Resources that request longer lead times without a physical constraint are rejected.

Table 6-20 shows the amount of nominated MW and locations by product type and lead time for the 2017/2018 Delivery Year. PJM approved 2,682 locations, or 17.1 percent of all locations, which have 3,681.5 nominated MW, or 40.2 percent of all nominated MW, for exceptions to the 30 minute lead time rule for the 2017/2018 Delivery Year.

46 PJM. "Manual 18B: Energy Efficiency Measurement & Verification," § 2.2 General Requirements of M&V Plan, Rev. 3 (November 17, 2016).

47 PJM. "Manual 18B: Energy Efficiency Measurement & Verification," § 1.1 Overview of Energy Efficiency, Rev. 3 (November 17, 2016).

48 See 147 FERC ¶ 61,103 (2014).

49 See PJM Interconnection, L.L.C., Docket No. ER14-135-000 (October 20, 2014).

50 See "PJM Manual 18: Capacity Market," § 4.3.1 Requirements of Load Management Products in RPM, Rev. 41 (Jan. 1, 2019).

Table 6-20 Nominated MW and locations by product type and lead time: 2017/2018 Delivery Year

	Pre-Emergency MW					Emergency MW					
Lead Type	Limited	Extended Summer	Annual	Capacity Performance	Pre-Emergency Total	Limited	Extended Summer	Annual	Capacity Performance	Emergency Total	Total
Quick Lead (30 Minutes)	1,410.8	3,137.9	418.0	280.6	5,247.3	51.1	160.4	7.5	7.0	225.9	5,473.2
Short Lead (60 Minutes)	129.5	140.8	46.0	79.6	395.9	3.0	13.2	0.0	0.0	16.1	412.0
Long Lead (120 Minutes)	822.6	1,701.2	476.6	156.4	3,156.7	18.8	43.1	44.7	6.2	112.8	3,269.6
Total	2,362.9	4,979.8	940.6	516.6	8,799.9	72.8	216.7	52.2	13.2	354.8	9,154.7
	Pre-Emergency Locations					Emergency Locations					
Lead Type	Limited	Extended Summer	Annual	Capacity Performance	Pre-Emergency Total	Limited	Extended Summer	Annual	Capacity Performance	Emergency Total	Total
Quick Lead (30 Minutes)	3,712	7,587	1,205	126	12,630	84	269	8	23	384	13,014
Short Lead (60 Minutes)	97	155	47	6	305	17	6	0	0	23	328
Long Lead (120 Minutes)	380	617	1,288	15	2,300	12	35	6	1	54	2,354
Total	4,189	8,359	2,540	147	15,235	113	310	14	24	461	15,696

Table 6-21 shows the amount of nominated MW and locations by product type and lead time for the 2018/2019 Delivery Year. PJM approved 2,627 locations, or 19.1 percent of all locations, which have 3,943.1 nominated MW, or 43.9 percent of all nominated MW, for exceptions to the 30 minute lead time rule for the 2018/2019 Delivery Year.

Table 6-21 Nominated MW and locations by product type and lead time: 2018/2019 Delivery Year

	Pre-Emergency MW					Emergency MW					
Lead Type	Limited	Annual	Base	Capacity Performance	Pre-Emergency Total	Limited	Annual	Base	Capacity Performance	Emergency Total	Total
Quick Lead (30 Minutes)	311.9	6.8	4,179.5	305.2	4,803.3	0.2	0.0	222.6	18.9	241.7	5,045.0
Short Lead (60 Minutes)	23.2	0.0	367.8	65.5	456.5	0.0	0.0	26.4	0.0	26.4	483.0
Long Lead (120 Minutes)	122.8	0.0	2,665.4	527.7	3,315.9	0.0	0.0	144.2	0.0	144.2	3,460.1
Total	457.8	6.8	7,212.7	898.4	8,575.7	0.2	0.0	393.3	18.9	412.4	8,988.1
	Pre-Emergency Locations					Emergency Locations					
Lead Type	Limited	Annual	Base	Capacity Performance	Pre-Emergency Total	Limited	Annual	Base	Capacity Performance	Emergency Total	Total
Quick Lead (30 Minutes)	167	2	9,900	686	10,755	4	0	330	45	379	11,134
Short Lead (60 Minutes)	12	0	280	30	322	0	0	22	0	22	344
Long Lead (120 Minutes)	33	0	1,802	374	2,209	0	0	74	0	74	2,283
Total	212	2	11,982	1,090	13,286	4	0	426	45	475	13,761

There are three different ways to measure load reductions of demand resources. The Firm Service Level (FSL) method measures the difference between a customer's peak load contribution (PLC) and real-time load, multiplied by the loss factor (LF). The Guaranteed Load Drop (GLD) method measures the minimum of: the comparison load minus real-time load multiplied by the loss factor; or the PLC minus the real-time load multiplied by the loss factor. The comparison load estimates what the load would have been if PJM did not declare a Load Management Event, similar to a CBL, by using a comparable day, same day, customer baseline, regression analysis or backup generation method. Limiting the GLD method to the minimum of the two calculations ensures reductions occur below the PLC, thus avoiding double counting of load reductions.[51] The implementation of a Winter Peak Load (WPL), effective for the 2017/2018 Delivery Year, measures capacity compliance during winter months from the WPL rather than the PLC.

The Capacity Market is an annual market. A Capacity Performance resource has an annual commitment. Load is allocated capacity obligations based on the annual peak load which is a summer load. The amount of MW allocated to load does not vary based on winter demand. The principle is that a customer's actual use of capacity should be compared to the level of capacity that a customer is required to pay for. Capacity costs are allocated to LSEs by PJM based on the single coincident peak load method. In PJM, the single coincident peak occurs in the summer.[52] LSEs generally allocate capacity costs to customers based on the five coincident peak method.[53] The allocation of capacity costs to customers uses each customer's PLC. Customers pay for capacity based on the PLC, not the WPL. The MMU

51 135 FERC ¶ 61,212.
52 OATT Attachment DD.5.11.
53 OATT Attachment M-2.

recommends setting the baseline for measuring capacity compliance under summer and winter compliance at the customer's PLC, similar to GLD, to avoid double counting, to avoid under counting and to ensure that a customer's purchase of capacity is calculated correctly. The Direct Load Control (DLC) method measures when the CSP turns on and turns off the direct load control switch to remotely trigger load reductions. DLC customers were not required to submit meter data to calculate load reductions. The direct load control method is no longer an eligible reduction method after May 31, 2016.[54] The FSL and GLD equations for calculating load reductions are:

FSL Reduction = PLC – (Load · LF)

GLD Reduction = Minimum of {(comparison load – Load) · LF; PLC – (Load · LF)}

Table 6-22 shows the MW registered by measurement and verification method and by technology type for the 2017/2018 Delivery Year. For the 2017/2018 Delivery Year, 99.4 percent use the FSL method and 0.6 percent use the GLD measurement and verification method.

Table 6-22 Reduction MW by each demand response method: 2017/2018 Delivery Year

	Technology Type								
Measurement and Verification Method	On-site Generation MW	HVAC MW	Refrigeration MW	Lighting MW	Manufacturing MW	Water Heating MW	Other, Batteries or Plug Load MW	Total	Percent by type
Firm Service Level	1,266.4	2,973.7	237.4	769.6	3,726.2	78.7	52.0	9,104.0	99.4%
Guaranteed Load Drop	8.9	19.4	1.6	3.6	17.1	0.1	-0.0	50.7	0.6%
Total	1,275.4	2,993.1	239.0	773.2	3,743.2	78.8	52.0	9,154.7	100.0%
Percent by method	13.9%	32.7%	2.6%	8.4%	40.9%	0.9%	0.6%	100.0%	

Table 6-23 shows the MW registered by measurement and verification method and by technology type for the 2018/2019 Delivery Year. For the 2018/2019 Delivery Year, 99.7 percent use the FSL method and 0.3 percent use the GLD measurement and verification method.

Table 6-23 Reduction MW by each demand response method: 2018/2019 Delivery Year

	Technology Type								
Measurement and Verification Method	On-site Generation MW	HVAC MW	Refrigeration MW	Lighting MW	Manufacturing MW	Water Heating MW	Other, Batteries or Plug Load MW	Total	Percent by type
Firm Service Level	1,147.2	2,688.8	210.1	622.1	4,134.4	116.4	41.6	8,960.7	99.7%
Guaranteed Load Drop	1.4	9.0	0.0	0.6	16.4	0.1	0.0	27.4	0.3%
Total	1,148.6	2,697.8	210.1	622.7	4,150.8	116.5	41.6	8,988.1	100.0%
Percent by method	12.8%	30.0%	2.3%	6.9%	46.2%	1.3%	0.5%	100.0%	

Table 6-24 shows the fuel type used in the onsite generators for the 2017/2018 Delivery Year. For the 2017/2018 Delivery Year, 1,275.4 MW of the 9,154.7 MW nominated MW, 13.9 percent, used onsite generation. Of the 1,275.4 MW using onsite generation, 74.5 percent of MW are diesel, 24.4 percent of MW are natural gas and 1.1 percent of MW are gasoline, kerosene, oil, propane or waste products. For the 2017/2018 Delivery Year, there are 354.5 MW, 27.8 percent, registered with an onsite generator in the emergency program.

Table 6-24 Onsite generation fuel type (MW): 2017/2018 Delivery Year

	2017/2018	
Fuel Type	MW	Percent
Diesel	950.1	74.5%
Natural Gas	311.3	24.4%
Gasoline, Kerosene, Oil, Propane, Waste Products	13.9	1.1%
Total	1,275.4	100.0%

54 "PJM Manual 18: PJM Capacity Market," Revision 28, Rev. 41 (Jan. 1, 2019).

Table 6-25 shows the fuel type used in the onsite generators for the 2018/2019 Delivery Year. During the 2018/2019 Delivery Year, 1,148.6 MW of the 8,988.1 MW of nominated MW, 12.8 percent, used onsite generation. Of the 1,148.6 MW, 84.3 percent of MW are diesel and 15.7 percent of MW are natural gas, gasoline, oil, propane or waste products. For the 2018/2019 Delivery Year, there are 354.5 MW, 27.8 percent, registered with an onsite generator in the emergency program.

Table 6-25 Onsite generation fuel type (MW): 2018/2019 Delivery Year

	2018/2019	
Fuel Type	MW	Percent
Diesel	968.8	84.3%
Natural Gas, Gasoline, Oil, Propane, Waste Products	179.8	15.7%
Total	1,148.6	100.0%

Emergency and Pre-Emergency Event Reported Compliance

Subzonal dispatch became mandatory for emergency demand resources in the 2014/2015 Delivery Year, if the subzone was defined by PJM no later than the day before the dispatch.[55] PJM does not measure compliance when demand response is dispatched in a subzone created on the same day as the dispatch. There are thirteen dispatchable subzones in PJM effective September 21, 2018: AEP_CANTON, ATSI_CLE, DPL_SOUTH, PS_NORTH, ATSI_NEWCASOE, PPL_WESCO, ATSI_BLKRIVER, PENELEC_ERIC, APS_EAST, DOM_CHES, DOM_YORKTOWN, AECO_ENGLAND, JCPL_REDBANK.[56] Effective with the 2020/2021 Delivery Year, PJM will procure a single capacity product, Capacity Performance, which does not require predefined subzones for mandatory dispatch.[57]

PJM can remove a defined subzone, and make changes to the subzone, at their discretion. Subzones should not be removed once defined, as the subzone may need to be dispatched again in the future. The METED_EAST, PENELEC_EAST, PPL_EAST and DOM_NORFOLK subzones were removed by PJM. More subzones may have been removed by PJM but PJM does not keep a record of created and removed subzones. The MMU recommends that PJM not remove any defined subzones and maintain a public record of all created and removed subzones.

The subzone design and closed loop interfaces are related. PJM implemented closed loop interfaces with the stated purpose of improving the incorporation of reactive constraints into energy prices and to allow emergency DR to set price.[58] PJM applies closed loop interfaces so that it can use units needed for reactive support to set the energy price when they would not otherwise set price under the LMP algorithm. PJM also applies closed loop interfaces so that it can use emergency DR resources to set the real-time LMP when DR resources would not otherwise set price under the fundamental LMP logic. Of the 20 closed loop interface definitions, 11 (55 percent) were created for the purpose of allowing emergency DR to set price.[59]

Demand resources can be dispatched for voluntary compliance during any hour of any day, but dispatched resources are not measured for compliance outside of the mandatory compliance window for each demand product. A demand response event during a product's mandatory compliance window also may not result in a compliance score. When limited, extended summer and annual demand response events occur for partial hours under 30 minutes or for a subzone dispatch that was not defined one business day before dispatch, the events are not measured for compliance.

Capacity Performance demand resources currently estimate five minute compliance with an hourly interval meter during PAIs. To accurately measure compliance on a five minute basis, a five minute interval meter is required. All other Capacity Performance resources require five minute interval meters, and demand resources should be no different. Limited, extended summer and annual demand resources are paid based on the average performance by registration for the duration of a demand response event. Each capacity performance demand response product should measure compliance on a five minute basis to accurately report reductions during demand response events. The current rules for limited, extended summer and annual demand response

55 OATT Attachment DD, Section 11.

56 See "Load Management Subzones," <http://www.pjm.com/~/media/markets-ops/demand-response/subzone-definition-workbook.ashx> (Accessed February 25, 2019).

57 OATT Attachment DD, Section 10A.

58 See PJM/Alstom. "Approaches to Reduce Energy Uplift and PJM Experiences," presented at the FERC Technical Conference: Increasing Real-Time and Day-Ahead Market Efficiency Through Improved Software in Docket No. AD10-12-006 <http://www.ferc.gov/june-tech-conf/2015/presentations/m2-3.pdf> (June 23, 2015).

59 See the *2018 State of the Market Report for PJM*, Volume 2, Section 4, Energy Uplift, for additional information regarding all closed loop interfaces and the impacts to the PJM markets.

use the average reduction for the duration of an event. The average duration across multiple hours does not provide an accurate metric for each five minute interval of the event and is inconsistent with the measurement of generation resources. Measuring compliance on a five minute basis would provide accurate information to the PJM system. 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.[60]

Annual and capacity performance demand response currently assign annual reduction capability by registration, which is measured as the lower of the summer and winter reduction capability. Starting with the 2019/2020 Delivery Year, CSPs will assign the annual reduction capability by portfolio rather than registration, which is measured as the lower of the summer and winter reduction capability by portfolio.[61] Allowing CSPs to aggregate to the portfolio level further weakens the locational aspect of registered demand resources and artificially inflates the level of demand response. For example, imagine a CSP has two registrations in a zonal portfolio, with one registration capable of reducing 5 MW in summer and 2 MW in winter, and the second registration capable of reducing 1 MW in summer and 5 MW in winter. Before the 2019/2020 Delivery Year, the first registration would have an annual capability of 2 MW and the second registration would have an annual capability of 1 MW resulting in a 3 MW total reduction capability. After the 2019/2020 Delivery Year, individual registration capability is ignored resulting in the portfolio capability of 6 MW in summer and 7 MW in winter. This creates a 6 MW total reduction capability within the zone. Without any change to either registration, the CSP was able to add 3 MW to their annual reduction capability. The locational availability of demand resources, at a nodal level, will vary. This treatment is unique to demand resources.

Under the capacity performance design of the PJM Capacity Market, compliance for potential penalties will be measured for DR only during performance assessment intervals (PAI).[62] When pre-emergency or emergency demand response is dispatched, a PAI is triggered for PJM. PJM cannot dispatch pre-emergency or emergency demand response without triggering a PAI and measuring compliance. Before PJM created PAI to measure compliance, pre-emergency demand response could be dispatched without calling an emergency event. As a result, PJM now effectively classifies all demand response as an emergency resource.

The MMU recommends that demand response resources be treated as economic resources like all other capacity resources and therefore that the dispatch of demand response resources not automatically trigger a performance assessment interval (PAI) for CP compliance. Emergencies should be triggered only when PJM has exhausted all economic resources including demand response resources. Table 6-26 shows the amount of nominated demand response MW, the required reserve margin and actual reserve margin as of June 1, 2017 and June 1, 2018. There are 8,988.1 nominated MW of demand response for the 2018/2019 Delivery Year, which is 40.0 percent of the required reserve margin and 28.1 percent of the actual reserve margin on June 1, 2018.[63]

Table 6-26 Demand response nominated MW compared to reserve margin: June 1, 2017 and June 1, 2018

	Demand Response Nominated MW	Required Reserve Margin	Demand Response Percent of Required Reserve Margin	Actual Reserve Margin	Demand Response Percent of Actual Reserve Margin
01-Jun-17	9,154.7	23,305.2	39.3%	33,828.1	27.1%
01-Jun-18	8,998.1	22,487.7	40.0%	31,987.5	28.1%

PJM will dispatch demand resources by zone or subzone for limited, extended summer and annual demand resources, or within a PAI area for Capacity Performance resources. When PJM dispatches all demand resources in multiple connecting zones, PJM further degrades the nodal design of electricity markets. PJM allows compliance to be measured across zones within a compliance aggregation area (CAA) or Emergency

60 "PJM Manual 18: Capacity Market," § 8.7A Measuring Compliance during Performance Assessment Interval for Demand Resources, Rev. 41 (Jan. 1, 2019).

61 The seasonal DR registration aggregation received endorsement at the September 27, 2018 MRC meeting, <https://www.pjm.com/-/media/committees-groups/committees/mc/20180927/20180927-consent-agenda-item-b-seasonal-dr-registration-aggregation-draft-oatt-revisions.ashx>.

62 OATT § 1 (Performance Assessment Hour).

63 *2018 State of the Market Report for PJM*, Volume 2, Section 5: Capacity, Table 5-7.

Action Area (EAA).[64 65] A CAA, or EAA, is an electrically connected area that has the same capacity market price. This changes the way CSPs dispatch resources when multiple electrically contiguous areas with the same RPM clearing prices are dispatched. The compliance rules determine how CSPs are paid and thus create incentives that CSPs will incorporate in their decisions about how to respond to PJM dispatch. The multiple zone approach is even less locational than the zonal and subzonal approaches and creates larger mismatches between the locational need for the resources and the actual response. If multiple zones within a CAA are called by PJM, a CSP will dispatch the least cost resources across the zones to cover the CSP's obligation. This can result in more MW dispatched in one zone that are locationally distant from the relief needed and no MW dispatched in another zone, yet the CSP could be considered 100 percent compliant and pay no penalties. More locational deployment of load management resources would improve efficiency. With full implementation of capacity performance, demand response will be dispatched by registrations within an area for which an Emergency Action is declared by PJM. PJM does not have the nodal location of each registration, meaning PJM will need to guess as to the useful demand response registration by registered location. The MMU recommends that demand resources be required to provide their nodal location. Nodal dispatch of demand resources would be consistent with the nodal dispatch of generation.

Definition of Compliance

Currently, the calculation methods of event and test compliance do not provide reliable results. PJM's interpretation of load management event rules allows over compliance to be reported when there is no actual over compliance. Settlement locations with a negative load reduction value (load increase) are not netted by PJM within registrations or within demand response portfolios. A resource that has load above their baseline during a demand response event has a negative performance value. PJM limits compliance shortfall values to zero MW. This is not explicitly stated in the Tariff or supporting Manuals and the compliance formulas for FSL and GLD customers do allow negative values.[66]

Limiting compliance to only positive values incorrectly calculates compliance. For example, if a registration had two locations, one with a 50 MWh load increase when called, and another with a 75 MWh load reduction when called, PJM calculates compliance for that registration as a 75 MWh load reduction for that event hour. Negative settlement MWh are not netted across hours or across registrations for compliance purposes. A location with a load increase is set to a zero MW reduction. For example, in a two hour event, if a registration showed a 15 MWh load increase in hour one, but a 30 MWh reduction in hour two, the registration would have a calculated 0 MWh reduction in hour one and a 30 MWh reduction in hour two. This has compliance calculated at an average hourly 15 MWh load reduction for that two hour event, compared to a 7.5 MWh observed reduction. Reported compliance is greater than observed compliance, as locations with load increases, i.e. negative reductions, are treated as zero for compliance purposes.

Changing a demand resource compliance calculation from a negative value to 0 MW inaccurately values event performance and capacity performance. Inflated compliance numbers for an event overstates the true value and capacity of demand resources. A demand response capacity resource that performs negatively is also displacing another capacity resource that could supply capacity during a delivery year. By setting the negative compliance value to 0 MW, PJM is inaccurately calculating the value of demand resources.

Load increases are not netted against load decreases for dispatched demand resources across hours or across registrations within hours for compliance purposes, but are treated as zero. This skews the compliance results towards higher compliance since poorly performing demand resources are not used in the compliance calculation. When load is above the peak load contribution during a demand response event, the load reduction is negative; it is a load increase rather than a decrease. PJM ignores such negative reduction values and instead replaces the negative values with a zero MW reduction value. The PJM Tariff and PJM Manuals do

64 CAA is "a geographic area of Zones or sub-Zones that are electrically contiguous and experience for the relevant Delivery Year, based on Resource Clear Prices of, for Delivery Years through May 31, 2018, Annual Resources and for the 2018/2019 Delivery Year and subsequent Delivery Years, Capacity Performance Resources, the same locational price separation in the Base Residual Auction, the same locational price separation in the First Incremental Auction, the same locational price separation in the Second Incremental Auction, or the same locational price separation in the Third Incremental Auction." OATT § 1.

65 PJM. "Manual 18: Capacity Market," § 8.7.2 Load Management Event Compliance Allocation, Rev. 41 (Jan. 1, 2019).

66 OA Schedule 1 § 8.9.

not limit the compliance calculation value to a zero MW reduction value.[67] The compliance values PJM reports for demand response events are different than the actual compliance values accounting for both increases and decreases in load from demand resources that are called on and paid under the program.

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.

Demand resources that are also registered as economic resources have a calculated CBL for the emergency event days. Demand resources that are not registered as Economic Resources use the three day CBL type with the symmetrical additive adjustment for measuring energy reductions without the requirements of a Relative Root Mean Squared Error (RRMSE) Test required for all economic resources.[68] The CBL must use the RRMSE test to verify that it is a good approximation for real time load usage. The MMU recommends the RRMSE test be required for all demand resources with a CBL.

An extreme example makes clear the fundamental problems with the use of measurement and verification methods to define the level of power that would have been used but for the DR actions, and the payments to DR customers that result from these methods. The current rules for measurement and verification for demand resources make a bankrupt company, a customer that no longer exists due to closing of a facility or a permanently shut down company, or a company with a permanent reduction in peak load due to a partial closing of a facility, an acceptable demand response customer under some interpretations of the tariff, although it is the view of the MMU that such customers should not be permitted to be included as registered demand resources. Companies that remain in business, but with a substantially reduced load, can maintain their pre-bankruptcy FSL (firm service level to which the customer agrees to reduce in an event) commitment, which can be greater than or equal to the post-bankruptcy peak load. The customer agrees to reduce to a level which is greater than or equal to its new peak load after bankruptcy. When demand response events occur the customer would receive credit for 100 percent reduction, even though the customer took no action and could take no action to reduce load. This problem exists regardless of whether the customer is still paying for capacity. To qualify and participate as a demand resource, the customer must have the ability to reduce load. "A participant that has the ability to reduce a measurable and verifiable portion of its load, as metered on an EDC account basis."[69] Such a customer no longer has the ability to reduce load in response to price or a PJM demand response event. CSPs in PJM have and continue to register bankrupt customers as DR customers. PJM finds acceptable the practice of CSPs maintaining the registration of customers with a bankruptcy related reduction in demand that are unable, as a result, to respond to emergency events. Three proposals that included language to remove bankrupt customers from a CSP's portfolio failed at the June 7, 2017, Market Implementation Committee.[70] The registered customers that are bankrupt and the amount of registered MW cannot be released for reasons of confidentiality.

The metering requirement for demand resources is outdated, and has not kept up with the changes to PJM's market design. PJM moved to five minute settlements, but the metering requirement for demand resources remained at an hourly interval meter. It is impossible to measure energy usage on a five basis using an hourly interval meter. PJM will estimate real time usage by prorating the hourly interval meter and assume if load is less than the CBL, that the reduction occurred during the required dispatch window. The meter reading is not telemetered to PJM in real time. The resource is allowed up to 60 days to report the data to PJM. The MMU recommends that PJM adopt the ISO-NE five-minute metering requirements in order to ensure that dispatchers have the necessary information for reliability and that market payments to demand resources be calculated based on interval meter data at the site of the demand reductions so that they can accurately measure compliance.[71]

67 OA Schedule 1 § 8.9.

68 157 FERC ¶ 61,067 (2016).

69 OA Schedule 1 § 8.2.

70 There was one proposal from PJM, one proposal from a market participant and one proposal from the MMU. See *Approved Minutes from the Market Implementation Committee*, <http://www.pjm.com/-/media/committees-groups/committees/mic/20170607/20170607-minutes.ashx>.

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

When demand resources are not dispatched during a mandatory response window, each CSP must test their portfolio to the levels of capacity commitment.[72] A CSP picks the testing day, for one hour, on any non-holiday weekday during the applicable mandatory window. A CSP is able to retest if a resource fails to provide the required reduction by less than 25 percent. The ability of CSPs to pick the test time does not simulate emergency conditions. As a result, test compliance is not an accurate representation of the capability of the resource to respond to an actual PJM dispatch of the resource. Given that demand resources are now an annual product, multiple tests are required to ensure reduction capability year round. The MMU recommends that load management testing be initiated by PJM with limited warning to CSPs in order to more accurately represent the conditions of an emergency event.

Table 6-27 shows the test penalties by delivery year by product type for the 2015/2016 Delivery Year through the 2017/2018 Delivery Year. The shortfall MW are calculated for each CSP by zone. The weighted rate per MW is the average penalty rate paid per MW. The total penalty column is the sum of the daily test penalties by delivery year and type. The testing window for the limited product is open through September. The testing window for the extended summer, annual and Capacity Performance product is open through the end of the delivery year.

Table 6-27 Test penalties by delivery year by product type: 2015/2016 through 2017/2018 Delivery Years

	2015/2016			2016/2017			2017/2018		
Product Type	Shortfall MW	Weighted Rate per MW	Total Penalty	Shortfall MW	Weighted Rate per MW	Total Penalty	Shortfall MW	Weighted Rate per MW	Total Penalty
Limited	96.4	$165.35	$5,836,255	48.9	$166.41	$2,967,158	13.9	$124.08	$631,665
Extended Summer	1.9	$163.70	$113,835	7.3	$138.14	$370,290	10.5	$142.86	$547,928
Annual	3.7	$184.67	$250,621	4.8	$137.45	$241,406	16.3	$144.00	$855,940
Base									
Capacity Performance				2.1	$160.80	$124,310	0.6	$181.80	$40,146
Total	102.0	$166.02	$6,200,711	63.1	$160.72	$3,703,163	41.3	$137.54	$2,075,678

Emergency Energy Payments

Emergency and pre-emergency demand response dispatched during a load management event by PJM are eligible to receive emergency energy payments if registered under the full program option. The full program option includes an energy payment for load reductions during a pre-emergency or emergency event for demand response events and capacity payments.[73] There were 98.2 percent of nominated MW for the 2017/2018 Delivery Year and 98.8 percent of nominated MW for the 2018/2019 Delivery Year registered under the full program option. There were 1.8 percent of nominated MW for the 2017/2018 Delivery Year and 1.2 percent of nominated MW for the 2018/2019 Delivery Year registered as capacity only option. Demand resources clear the capacity market like all other capacity resources and the dispatch of demand resources should not trigger a scarcity event. The strike price is set by the CSP before the delivery year starts and cannot be changed during the delivery year. The demand resource energy payments are equal to the higher of hourly zonal LMP or a strike price energy offer made by the participant, including a dollar per MWh minimum dispatch price and an associated shutdown cost. Demand resources should not be permitted to offer above $1,000 per MWh without cost justification or to include a shortage penalty in the offer. FERC has stated clearly that demand resources in the capacity market must verify costs above $1,000 per MWh, unless they are capacity only. "We clarify, however, that reforms adopted in this Final Rule, which

72 The mandatory response time for Limited DR is June through September between 12:00PM to 8:00PM EPT, for Extended Summer is June through October and the following May between 10:00AM to 10:00PM EPT, for Annual DR is June through October and the following May between 10:00AM to 10:00PM and is November through April between 6:00AM to 9:00PM EPT, for Base Capacity DR is June through September between 10:00AM to 10:00PM EPT, Capacity Performance DR is June through October and the following May between 10:00AM to 10:00PM EPT and November through April between 6:00AM through 9:00PM EPT. See PJM. "Manual 18: Capacity Market," Rev. 41 (Jan. 1, 2019).

73 *Id.*

provide that resources are eligible to submit cost-based incremental energy offers in excess of $1,000/MWh and require that those offers be verified, do not apply to capacity-only demand response resources that do not submit incremental energy offers in energy markets."[74] PJM interprets the scarcity pricing rules to allow a maximum DR energy price of $1,849 per MWh for the 2017/2018 Delivery Year and the 2018/2019 Delivery Year.[75] [76] Demand resources registered with the full option should be required to verify energy offers in excess of $1,000 per MWh. PJM does not require such verification.[77] The MMU recommends that the maximum offer for demand resources be the same as the maximum offer for generation resources.

Shutdown costs for demand response resources are not adequately defined in Manual 15. PJM's Cost Development Subcommittee (CDS) approved changes to Manual 15 to eliminate shutdown costs for demand response resources participating in the Synchronized Reserve Market, but not demand resources or economic resources.[78]

Table 6-28 Distribution of registrations and associated MW in the full option across ranges of minimum dispatch: 2017/2018 Delivery Year

Ranges of Strike Prices ($/MWh)	Locations	Percent of Total	Nominated MW (ICAP)	Percent of Total	Shutdown Cost per Location	Shutdown Cost Per Nominated MW (ICAP)
$0-$1	459	2.9%	53.9	0.6%	$0.00	$0.00
$1-$999	291	1.9%	305.4	3.4%	$77.61	$73.94
$999-$1,100	1,288	8.3%	328.6	3.7%	$239.13	$937.37
$1,100-$1,275	1,789	11.5%	2,925.9	32.5%	$94.68	$57.89
$1,275-$1,550	315	2.0%	283.5	3.2%	$57.43	$63.81
$1,550-$1,849	11,437	73.4%	5,093.4	56.7%	$44.54	$100.01
Total	15,579	100.0%	8,990.8	100.0%	$65.95	$114.28

Table 6-28 shows the distribution of registrations and associated MW in the emergency full option across ranges of minimum dispatch prices for the 2017/2018 Delivery Year. The majority of participants, 73.4 percent of locations and 65.7 percent of nominated MW, have a minimum dispatch price between $1,550 and $1,849 per MWh, which is the maximum price allowed for the 2017/2018 Delivery Year, 4.8 percent of location and 4.0 percent of nominated MW have a dispatch price between $0 and $999 per MWh, and 95.2 percent of locations and 96.0 percent of nominated MW have a dispatch price above $1,000 per MWh. The shutdown cost of resources with $999 to $1,100 per MWh strike prices had the highest average at $239.13 per location and $937.37 per nominated MW.

Table 6-29 shows the distribution of registrations and associated MW in the emergency full option across ranges of minimum dispatch prices for the 2018/2019 Delivery Year. The majority of participants, 78.4 percent of locations and 53.9 percent of nominated MW, have a minimum dispatch price between $1,550 and $1,849 per MWh, which is the maximum price allowed for the 2018/2019 Delivery Year, 2.8 percent of locations and 7.2 percent of nominated MW have a dispatch price between $0 and $1,100 per MWh, and 97.2 percent of locations and 92.8 percent of nominated MW have a dispatch price above $1,100 per MWh. The shutdown cost of resources with $0 to $1,100 per MWh strike prices had the highest average at $213.51 per location and $397.58 per nominated MW.

74 161 FERC ¶ 61,153 (2017).
75 139 FERC ¶ 61,057 (2012).
76 FERC accepted proposed changes to have the maximum strike price for 30 minute demand response to be $1,000/MWh + 1*Shortage penalty - $1.00, for 60 minute demand response to be $1,000/MWh + (Shortage Penalty/2) and for 120 minute demand response to be $1,100/MWh from ER14-822-000.
77 OATT Attachment K Appendix Section 1.10.1A Day-ahead Energy Market Scheduling (d) (x).
78 "PJM Manual 15: Cost Development Guidelines," § 8.1, Rev. 30 (Dec. 4, 2018).

Table 6-29 Distribution of registrations and associated MW in the full option across ranges of minimum dispatch: 2018/2019 Delivery Year

Ranges of Strike Prices ($/MWh)	Locations	Percent of Total	Nominated MW (ICAP)	Percent of Total	Shutdown Cost per Location	Shutdown Cost Per Nominated MW (ICAP)
$0-$1,100	383	2.8%	637.5	7.2%	$213.51	$397.58
$1,100-$1,275	2,235	16.4%	3,069.9	34.6%	$140.16	$102.05
$1,275-$1,550	325	2.4%	380.6	4.3%	$56.77	$48.48
$1,550-$1,849	10,695	78.4%	4,776.1	53.9%	$52.95	$118.57
Total	13,638	100.0%	8,864.1	100.0%	$71.84	$110.54

Distributed Energy Resources

Distributed Energy Resources (DER) are not well defined, but generally include small scale generation directly connected to the grid, generation connected to distribution level facilities and behind the meter generation.[79] For example, Table 6-24 shows the fuel mix of behind the meter generation participating as emergency demand response in the 2017/2018 Delivery Year. Clear rules for defining DERs and for defining the ways in which DERs will interact with the wholesale power markets do not yet exist, although the development of those rules is under active discussion.[80] [81] DERs should be treated like other resources. Creating preferential treatment for DERs could create an incentive to move resources behind the meter in a manner inconsistent with efficiency and competitive markets. FERC directed that DER aggregation be as geographically broad as technically feasible.[82]

The current demand response rules appropriately restrict demand response from injecting power into the grid and receiving demand response revenue. At the January 30, 2019, Demand Response Subcommittee meeting, PJM without a stakeholder process or FERC approval, decided to allow some economic DR payments when DR injects power into the grid. PJM's test compares the total benefits of running the generator which includes generation payments and assumed retail rate savings against the total cost of the generator. If the total cost of the generator is greater than the benefits, then the resource would receive economic DR payments while injecting. The use of a retail rate in calculating wholesale power market benefits raises significant issues analogous to net metering that require discussion and tariff changes. PJM should not include retail rate benefits in the definition of demand response without approval of FERC.

Aggregation to a single node is technically feasible. Allowing DER aggregation across nodes is not necessary and is not consistent with the nodal market design. Getting the rules correct at the beginning of DER development is essential to the active and effective participation of DER in the wholesale power markets in a manner that enhances rather than undercuts the efficiency and competitiveness of the power markets.

79 Some energy storage facilities may be DERs. The February 15, 2018, FERC Order No. 841 requires that energy storage resources have access to capacity, energy and ancillary service markets. 162 FERC ¶ 61,127, at P 1 (2018).

80 In PJM, the Distributed Energy Resources Subcommittee (DERSC) is currently discussing these issues. *Distributed Energy Resources Subcommittee*, PJM, <http://www.pjm.com/committees-and-groups/subcommittees/ders.aspx>.

81 See "Notice of Technical Conference," Docket No. RM18-9-000 and AD18-10-000 (February 15, 2018); "Technical Conference Distributed Energy Resources," Docket No. RM18-9-000 and AD18-10-000 (April 10, 2018).

82 162 FERC ¶ 32,718 at P 139 (2016).

Net Revenue

The Market Monitoring Unit (MMU) analyzed measures of PJM energy market structure, participant conduct and market performance. As part of the review of market performance, the MMU analyzed the net revenues earned by combustion turbine (CT), combined cycle (CC), coal plant (CP), diesel (DS), nuclear (NP), solar, and wind generating units.

Overview

Net Revenue

- Energy net revenues are significantly affected by energy prices and fuel prices. Energy prices and fuel prices were higher in 2018 than in 2017. Energy prices increased more than gas prices in most locations except for Texas Eastern M-3 gas and CTs and CCs ran with higher margins as a result. Coal prices increased by less than gas prices and CPs ran for more hours and at higher margins in 2018 than in 2017.
- In 2018, average energy market net revenues increased by 39 percent for a new CT, 48 percent for a new CC, 138 percent for a new CP, 32 percent for a new nuclear plant, 255 percent for a new DS, 24 percent for a new on shore wind installation, 26 percent for a new off shore wind installation and 10 percent for a new solar installation compared to 2017.
- The relative prices of fuel varied during 2018. While the marginal cost of the new CC was consistently below that of the new CP in 2018, the marginal cost of the new CT was above that of the new CP in January and December.
- Capacity revenue accounted for 47 percent of total net revenues for a new CT, 36 percent for a new CC, 48 percent for a new CP, 87 percent for a new DS, and 21 percent for a new nuclear plant.
- In 2018, a new CT would have received sufficient net revenue to cover levelized total costs in 11 zones and would have covered at least 87 percent of levelized costs in all zones as a result of higher energy prices and higher locational capacity market prices.
- In 2018, a new CC would have received sufficient net revenue to cover levelized total costs in all zones.
- In 2018, a new CP would not have received sufficient net revenue to cover levelized total costs in any zone.
- In 2018, a new nuclear plant would not have received sufficient net revenue to cover levelized total costs in any zone.
- In 2018, net revenues covered more than 64 percent of the annual levelized total costs of a new entrant on shore wind installation in AEP, APS, ComEd and PENELEC. Renewable energy credits accounted for at least 30 percent of the total net revenue of an on shore wind installation.
- In 2018, net revenues covered 49 percent of the annual levelized total costs of a new entrant off shore wind installation in AECO. Renewable energy credits accounted for 31 percent of the total net revenue of an off shore wind installation.
- In 2018, net revenues covered more than 100 percent of the annual levelized total costs of a new entrant solar installation in AECO, Dominion, JCPL and PSEG. Renewable energy credits accounted for at least 64 percent of the total net revenue of a solar installation.
- In 2018, most units did not achieve full recovery of avoidable costs through net revenue from energy markets alone, illustrating the critical role of the PJM Capacity Market in providing incentives for continued operation and investment. In 2018, capacity revenues were sufficient to cover the shortfall between energy revenues and avoidable costs for the majority of units and technology types in PJM, with the exception of some coal units and some nuclear units.
- Using a forward analysis, a total of 14,954 MW of coal and nuclear capacity are at risk of retirement, in addition to the units that are currently planning to retire. The 14,954 MW considered to be at risk of retirement consists of 12,017 MW of coal and 2,937 MW of nuclear capacity.

Historical New Entrant CT and CC Revenue Adequacy

Total unit net revenues include energy and capacity revenues. Analysis of the total unit revenues of theoretical new entrant CTs and CCs for three representative locations shows that CT and CC units that entered the PJM markets in 2007 have not covered their total costs, including the return on and of capital, on a cumulative basis. The analysis also shows that theoretical new entrant CTs and CCs that entered the PJM markets in 2012 have covered their total costs on a cumulative basis in the eastern PSEG and BGE zones but have not covered total costs in the western ComEd Zone. Energy market revenues alone were not sufficient to cover total costs in any scenario, which demonstrates the critical role of the capacity market revenue in covering total costs.

Conclusion

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

Unlike cost of service regulation, markets do not guarantee that units will cover their costs. CC units that entered the PJM markets in 2007 have covered their total costs, including the return on and of capital, on a cumulative basis in the eastern PSEG and BGE zones but have not covered total costs in the western ComEd Zone. The analysis also shows that theoretical new entrant CTs and CCs that entered the PJM markets in 2012 have covered their total costs on a cumulative basis in the eastern PSEG and BGE zones but have not covered total costs in the western ComEd Zone.

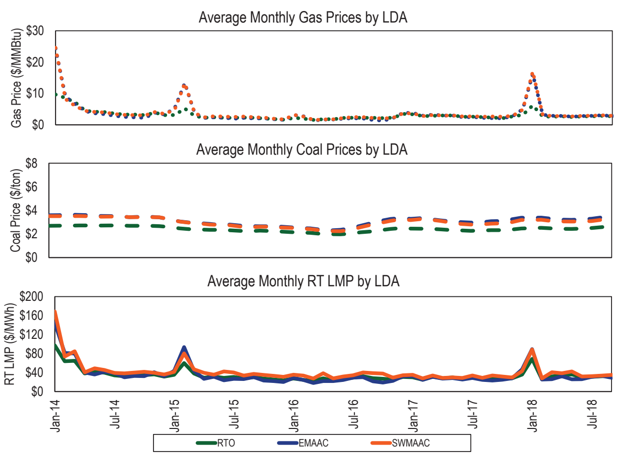
Net Revenue

When compared to annualized fixed costs and avoidable costs, net revenue is an indicator of generation investment profitability, and thus is a measure of overall market performance as well as a measure of the incentive to invest in new generation to serve PJM markets. Net revenue equals total revenue received by generators from PJM energy, capacity and ancillary service markets and from the provision of black start and reactive services less the short run marginal costs of energy production. In other words, net revenue is the amount that remains, after the short run marginal costs of energy production have been subtracted from gross revenue. Net revenues cover fixed costs, which include a return on investment, depreciation and income taxes, and avoidable costs, which include long term and intermediate term operation and maintenance expenses. Net revenue is the contribution to total fixed and avoidable costs received by generators from all PJM markets.

In a perfectly competitive, energy only market in long run equilibrium, net revenue from the energy market would be expected to equal the total of all annualized fixed and avoidable costs for the marginal unit, including a competitive return on investment. The PJM market design includes other markets intended to contribute to the payment of fixed and avoidable costs. In PJM, the energy, capacity and ancillary service markets are all significant sources of revenue to cover the fixed and avoidable costs of generators, as are payments for the provision of black start and reactive services. Thus, in a perfectly competitive market in long run equilibrium, with energy, capacity and ancillary service revenues, net revenue from all sources would be expected to equal the annualized fixed and avoidable costs of generation for the marginal unit. Net revenue is a measure of whether generators are receiving competitive returns on invested capital and of whether market prices are high enough to encourage entry of new capacity. In actual wholesale power markets, where equilibrium seldom occurs, net revenue is expected to fluctuate above and below the equilibrium level based on actual conditions in all relevant markets.

Net revenues are significantly affected by energy prices, fuel prices and capacity prices. The load-weighted average real-time LMP was 23.4 percent higher in 2018 than in 2017, $38.24 per MWh versus $30.99 per MWh. Eastern natural gas prices and coal prices increased in 2018. The price of Northern Appalachian coal was 10.0 percent higher; the price of Central Appalachian coal was 12.0 percent higher; the price of Powder River Basin coal was 2.8 percent higher; the price of eastern natural gas was 43.8 percent higher; and the price of western natural gas was 10.1 percent higher (Figure 7-1).

Figure 7-1 Energy market net revenue factor trends: 2014 through 2018



Spark Spreads, Dark Spreads, and Quark Spreads

The spark, dark, or quark spread is defined as the difference between the LMP received for selling power and the cost of fuel used to generate power, converted to a cost per MWh. The spark spread compares power prices to the cost of gas, the dark spread compares power prices to the cost of coal, and the quark spread compares power prices to the cost of uranium. The spread is a measure of the approximate difference between revenues and marginal costs and is an indicator of net revenue and profitability.

$$Spread\left(\frac{\$}{MWh}\right) = LMP\left(\frac{\$}{MWh}\right) - Fuel\ Price\left(\frac{\$}{MMBtu}\right) * Heat\ Rate\left(\frac{MMBtu}{MWh}\right)$$

Spread volatility is a result of fluctuations in LMP and the price of fuel. Spreads can be positive or negative. While both energy prices and gas prices increased in January 2018, hourly energy prices did not increase as much as gas prices, which lead to negative spark spreads during some high LMP hours. As a result, the volatility of the spark spreads is significantly higher than in previous years.

Table 7-1 shows average peak hour spreads by year and Table 7-2 shows the associated standard deviation.

Table 7-1 Peak hour spreads ($/MWh): 2014 through 2018

	BGE			ComEd			PSEG			Western Hub		
	Spark	Dark	Quark	Spark	Dark	Quark	Spark	Dark	Quark	Spark	Dark	Quark
2014	$30.27	$51.11	$66.58	$11.14	$42.50	$43.23	$19.85	$43.01	$60.19	$23.23	$39.58	$55.05
2015	$25.86	$34.71	$44.42	$14.48	$27.68	$26.98	$13.53	$23.38	$34.31	$23.59	$25.29	$35.00
2016	$28.29	$28.11	$38.32	$14.22	$25.72	$26.58	$13.44	$10.80	$24.06	$21.47	$18.53	$28.75
2017	$16.77	$18.41	$33.20	$11.81	$25.40	$28.19	$12.80	$10.89	$29.97	$16.30	$15.71	$30.50
2018	$15.64	$25.17	$41.16	$12.42	$26.62	$29.27	$7.61	$12.35	$34.23	$15.83	$21.05	$37.04

Table 7-2 Peak hour spread standard deviation ($/MWh): 2014 through 2018

	BGE			ComEd			PSEG			Western Hub		
	Spark	Dark	Quark	Spark	Dark	Quark	Spark	Dark	Quark	Spark	Dark	Quark
2014	$88.1	$118.9	$118.9	$68.1	$68.3	$68.3	$78.3	$94.0	$94.3	$83.0	$86.7	$86.7
2015	$42.4	$44.9	$45.0	$20.8	$22.5	$22.5	$32.7	$40.9	$41.1	$31.3	$33.1	$33.4
2016	$32.8	$32.6	$32.6	$16.4	$16.6	$16.8	$17.0	$18.6	$18.4	$19.1	$18.5	$18.5
2017	$23.5	$25.0	$25.0	$19.8	$19.9	$19.9	$19.9	$22.9	$23.0	$23.2	$22.5	$22.6
2018	$50.5	$36.9	$36.9	$17.0	$18.0	$17.9	$51.9	$33.3	$33.2	$42.3	$30.5	$30.4

Figure 7-2 shows the hourly spark spread, Figure 7-3 shows the hourly dark spread, and Figure 7-4 shows the hourly quark spread for peak hours for BGE, ComEd, PSEG, and Western Hub.

Figure 7-2 Hourly spark spread (gas) for peak hours ($/MWh): 2017 through 2018[1]

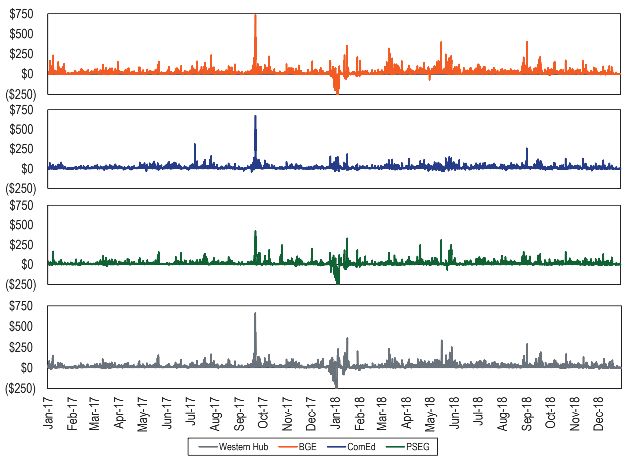


Figure 7-3 Hourly dark spread (coal) for peak hours ($/MWh): 2017 through 2018[2]

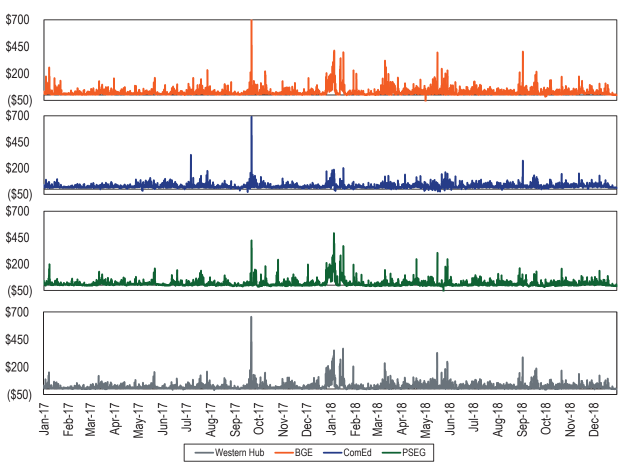
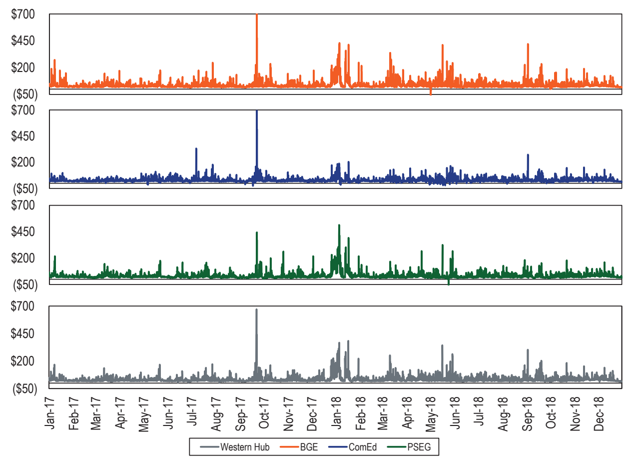


Figure 7-4 Hourly quark spread (uranium) for selected zones ($/MWh): 2017 through 2018[3]



Theoretical Energy Market Net Revenue

The net revenues presented in this section are theoretical as they are based on explicitly stated assumptions about how a new unit with specific characteristics would operate under economic dispatch. The economic dispatch uses technology specific operating constraints in the calculation of a new entrant's operations and potential net revenue in PJM markets.

The analysis in this report includes only energy revenues unless explicitly stated. The analysis in the annual state of the market report includes revenues from all PJM markets.

Analysis of energy market net revenues for a new entrant includes seven power plant configurations:

- The CT plant has an installed capacity of 360.1 MW and consists of one GE Frame 7HA.02 CT, equipped with evaporative coolers and selective catalytic reduction (SCR) for NO_x reduction.
- The CC plant has an installed capacity of 1,137.2 MW and consists of two GE Frame 7HA.02 CTs

1 Spark spreads use a combined cycle heat rate of 7,000 Btu/kWh, zonal hourly LMPs and daily gas prices; Chicago City Gate for ComEd, Zone 6 non-NY for BGE, Zone 6 NY for PSEG, and Texas Eastern M3 for Western Hub.

2 Dark spreads use a heat rate of 10,000 Btu/kWh, zonal hourly LMPs and daily coal prices; Powder River Basin coal for ComEd, Northern Appalachian coal for BGE and Western Hub, and Central Appalachian coal for PSEG.

3 Quark spreads use a heat rate of 10,000 Btu/kWh, zonal hourly LMPs, and daily uranium prices.

equipped with evaporative cooling, duct burners, a heat recovery steam generator (HRSG) for each CT with steam reheat and SCR for NO_x reduction with a single steam turbine generator.

- The CP has an installed capacity of 600.0 MW and is a sub-critical steam unit, equipped with selective catalytic reduction system (SCR) for NO_x control, a flue gas desulphurization (FGD) system with chemical injection for SO_x and mercury control, and a bag-house for particulate control.
- The DS plant has an installed capacity of 2.0 MW and consists of one oil fired CAT 2 MW unit using New York Harbor ultra low sulfur diesel.
- The nuclear plant has an installed capacity of 2,200 MW and consists of two units and related facilities using the Westinghouse AP1000 technology.
- The on shore wind installation consists of 37 Siemens 2.7 MW wind turbines totaling 99.9 MW installed capacity.
- The off shore wind installation consists of 43 Siemens 7.0 MW wind turbines totaling 301.0 MW installed capacity.
- The solar installation consists of a 35.5 acre ground mounted solar farm totaling 10 MW of AC installed capacity.

Net revenue calculations for the CT, CC and CP include the hourly effect of actual local ambient air temperature on plant heat rates and generator output for each of the three plant configurations.[4 5] Plant heat rates account for the efficiency changes and corresponding cost changes resulting from ambient air temperatures.

CO_2, NO_x and SO_2 emission allowance costs are included in the hourly plant dispatch cost, the short run marginal cost. CO_2, NO_x and SO_2 emission allowance costs were obtained from daily spot cash prices.[6]

A forced outage rate for each class of plant was calculated from PJM data and incorporated into all revenue calculations.[7] In addition, each CT, CC, CP, and DS plant was assumed to take a continuous 14 day planned annual outage in the fall season.

CT revenues for the provision of reactive services are based on the average reactive revenue per MW-year received by all CTs with 20 or fewer operating years. CC revenues for the provision of reactive services are based on the average reactive revenue per MW-year received by all CC generators with 20 or fewer operating years. CP revenues for the provision of reactive services are based on the average reactive revenue per MW-year received by all CP generators with 60 or fewer operating years. Table 7-3 includes reactive capability revenue of $3,350/MW-Yr for all unit types plus reactive service revenue.[8]

Table 7-3 New entrant reactive revenue (Dollars per MW-year)

	Reactive		
	CT	CC	CP
2014	$3,721	$4,046	$3,574
2015	$3,673	$4,911	$3,386
2016	$3,436	$4,573	$3,470
2017	$3,885	$3,591	$3,438
2018	$4,150	$3,350	$4,929

Zonal net revenues reflect zonal fuel costs based on locational fuel indices and zone specific delivery charges.[9] The delivered fuel cost for natural gas reflects the zonal, daily delivered price of natural gas and is from published commodity daily cash prices, with a basis adjustment for transportation costs.[10] The delivered cost of coal reflects the zone specific, delivered price of coal and was developed from the published prompt-month prices, adjusted for rail transportation costs.[11]

Short run marginal cost includes fuel costs, emissions costs, and the short run marginal component of VOM costs.[12 13] Average short run marginal costs are shown, including all components, in Table 7-4 and the short run marginal component of VOM is also shown separately.

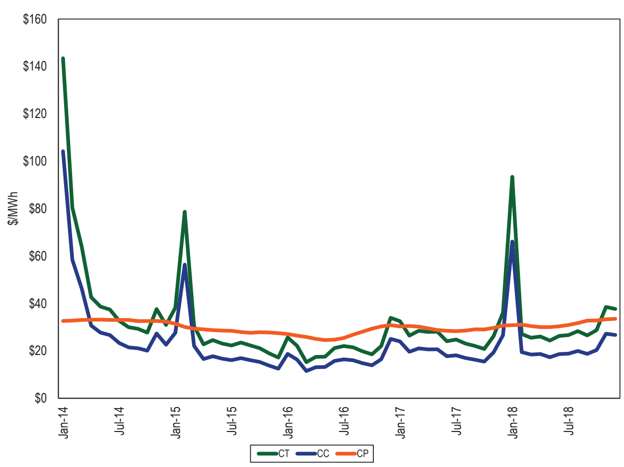
4 Hourly ambient conditions supplied by DTN.
5 Heat rates provided by Pasteris Energy, Inc. No-load costs are included in the dispatch price since each unit type is dispatched at full load for every economic hour resulting in a single offer point.
6 CO_2, NO_x and SO_2 emission daily prompt prices obtained from Evolution Markets, Inc.
7 Outage figures obtained from the PJM eGADS database.
8 $3,350/MW-Yr is the average of reactive capability payments of selected units obtained from FERC filings.
9 Startup fuel burns and emission rates provided by Pasteris Energy, Inc. Startup station power consumption costs were obtained from the station service rates published quarterly by PJM and netted against the MW produced during startup at the preceding applicable hourly LMP. All starts associated with combined cycle units are assumed to be hot starts.
10 Gas daily cash prices obtained from Platts.
11 Coal prompt prices obtained from Platts.
12 Fuel costs are calculated using the daily spot price and may not equal what participants actually paid.
13 VOM rates provided by Pasteris Energy, Inc.

Table 7-4 Average short run marginal costs: 2018

Unit Type	Short Run Marginal Costs ($/MWh)	Heat Rate (Btu/kWh)	VOM ($/MWh)
CT	$34.10	9,241	$0.38
CC	$24.21	6,296	$1.09
CP	$31.48	9,250	$4.03
DS	$161.16	9,660	$0.25
Nuclear	$8.50	NA	$3.00
Wind	$0.00	NA	$0.00
Wind (off shore)	$0.00	NA	$0.00
Solar	$0.00	NA	$0.00

A comparison of the monthly average short run marginal cost of the theoretical CT, CC and CP plants since 2014, shows that, on average, the short run marginal costs of the CC plant have been less than those of the CP plant but the costs of the CC plant have been more volatile than the costs of the CP plant as a result of the higher volatility of gas prices compared to coal prices (Figure 7-5).

Figure 7-5 Average short run marginal costs: 2014 through 2018



The net revenue measure does not include the potentially significant contribution from the explicit or implicit sale of the option value of physical units or from bilateral agreements to sell output at a price other than the PJM day-ahead or real-time energy market prices, e.g., a forward price.

Gas prices, coal prices, and energy prices are reflected in new entrant run hours. Table 7-5 shows the average run hours by a new entrant unit.

Table 7-5 Average run hours: 2014 through 2018

	CT	CC	CP	DS	Nuclear
2014	4,722	7,908	6,693	153	8,760
2015	6,266	8,133	5,605	141	8,760
2016	6,337	8,264	5,025	44	8,784
2017	4,974	8,230	4,520	38	8,760
2018	4,925	8,190	4,971	116	8,760

Capacity Market Net Revenue

Generators receive revenue from the sale of capacity in addition to revenue from the energy and ancillary service markets. In the PJM market design, the sale of capacity provides an important source of revenues to cover generator going forward costs and fixed costs. Capacity revenue for 2018 includes five months of the 2017/2018 capacity market clearing price and seven months of the 2018/2019 RPM capacity market clearing price.[14]

Table 7-6 Capacity revenue by PJM zones (Dollars per MW-year): 2014 through 2018[15]

Zone	2014	2015	2016	2017	2018
AECO	$66,206	$56,448	$50,948	$43,669	$65,655
AEP	$31,149	$48,128	$33,377	$34,645	$53,235
APS	$31,149	$48,128	$33,377	$34,645	$53,216
ATSI	$31,149	$95,422	$78,709	$42,929	$53,124
BGE	$63,360	$56,448	$50,948	$43,669	$52,953
ComEd	$31,149	$48,128	$33,377	$34,645	$63,994
DAY	$31,149	$48,128	$33,377	$34,645	$52,760
DEOK	$31,149	$48,128	$33,377	$34,645	$52,338
DLCO	$31,149	$48,128	$33,377	$34,645	$53,045
Dominion	$31,149	$48,128	$33,377	$34,645	$53,219
DPL	$66,206	$56,448	$50,948	$43,669	$65,106
EKPC	$31,149	$48,128	$33,377	$34,645	$52,400
JCPL	$66,206	$56,448	$50,948	$43,669	$64,763
Met-Ed	$63,360	$56,448	$50,948	$43,669	$53,353
PECO	$66,206	$56,448	$50,948	$43,669	$65,707
PENELEC	$63,360	$56,448	$50,945	$43,667	$53,154
Pepco	$66,529	$56,448	$50,948	$43,669	$53,323
PPL	$63,360	$56,448	$50,948	$43,669	$52,218
PSEG	$72,567	$60,936	$67,224	$73,401	$79,190
RECO	$72,567	$60,936	$67,224	$73,401	$79,190
PJM	$46,247	$54,646	$48,568	$44,809	$58,432

14 The RPM revenue values for PJM are load-weighted average clearing prices across the relevant base residual auctions.

15 See the *2018 State of the Market Report for PJM*, Appendix A: "PJM Geography," for details on the expansion of the PJM footprint.

Net Revenue Adequacy

When total net revenues exceed the annual, nominal levelized total costs for the technology, that technology is covering all its costs including a return on and of capital and all the expenses of operating the facility.

The extent to which net revenues cover the levelized total costs of investment is significantly dependent on technology type and location, which affect both energy and capacity revenue. Table 7-7 includes new entrant levelized total costs for selected technologies. The levelized total costs of all the technologies increased in 2018 over 2017 with the exception of the CC, diesel and nuclear plant.

Net revenues include net revenues from the PJM energy market, from the PJM Capacity Market and from any applicable ancillary services plus RECs for wind installations and SRECs for solar installations.

Levelized Total Costs

Table 7-7 New entrant 20-year levelized total costs (By plant type (Dollars per installed MW-year))[16 17 18]

	20-Year Levelized Total Cost				
	2014	2015	2016	2017	2018
Combustion Turbine	$122,604	$120,675	$119,346	$114,557	$118,116
Combined Cycle	$146,443	$146,300	$148,327	$129,731	$113,641
Coal Plant	$504,050	$517,017	$523,540	$528,701	$562,747
Diesel Plant	$161,746	$170,500	$173,182	$158,817	$154,683
Nuclear Plant	$880,770	$935,659	$963,107	$1,349,850	$1,178,607
On Shore Wind Installation (with 1603 grant)	$198,033	$202,874	$231,310	$188,747	$214,780
Off Shore Wind Installation (with 1603 grant)	-	-	-	-	$683,771
Solar Installation (with 1603 grant)	$236,289	$234,151	$218,937	$200,931	$232,230

Levelized Cost of Energy

The levelized cost of energy is a measure of the total cost per MWh of energy from a technology, including all fixed and variable costs. If a unit's revenues cover its levelized cost of energy, it is covering all its costs and earning the target rate of return. Table 7-8 shows the levelized cost of energy for a new entrant unit by technology type operating at the capacity factor for the new entrant unit type. CCs had a low levelized cost of energy in 2018 because they had a high capacity factor, which increases the MWh over which costs are spread. DS units had a high levelized cost of energy in 2018 because DS units ran for extremely few hours, which decreases the capacity factor, which decreases the MWh over which costs are spread. The levelized cost of on shore wind is comparable to or less than that of all other resources except CCs. The levelized cost of solar is high as a result of a low capacity factor.

Table 7-8 Levelized cost of energy: 2018

	CT	CC	CP	DS	Nuclear	Wind (On Shore)	Wind (Off Shore)	Solar
Levelized cost ($/MW-Yr)	$118,116	$113,641	$562,747	$154,683	$1,178,607	$214,780	$460,730	$232,230
Short run marginal costs ($/MWh)	$34.10	$24.21	$31.48	$161.16	$8.50	$0.00	$0.00	$0.00
Capacity factor (%)	54%	88%	49%	2%	94%	28%	45%	13%
Levelized cost of energy ($/MWh)	$59	$39	$161	$882	$151	$88	$117	$198

16 Levelized total costs provided by Pasteris Energy, Inc.

17 Under Section 1603 of the American Recovery and Reinvestment Tax Act of 2009 the United States Department of the Treasury makes payments to owners who place in service specified energy property and apply for such payments. The purpose of the payment is to reimburse eligible applicants for a portion of the capital cost of such property. Solar and wind energy properties are eligible for a 30 percent payment of the total eligible capital cost of the project. This 30 percent payment reduced the calculated fixed nominal levelized revenue requirements of the solar and wind technologies.

18 Combustion turbine levelized total costs presented for 2018 have been updated since the 2017 State of the Market Report for a one CT configuration.

New Entrant Combustion Turbine

Energy market net revenue was calculated for a new CT plant economically dispatched by PJM. It was assumed that the CT plant had a minimum run time of two hours. The unit was first committed day ahead in profitable blocks of at least two hours, including start costs. If the unit was not already committed day ahead, it was run in real time in standalone profitable blocks of at least two hours, or any profitable hours bordering the profitable day-ahead or real-time block.

The new entrant CT is larger and more efficient than most CTs currently operating in PJM. The economically dispatched new entrant CT ran for more than twice as many hours as large CTs currently operating in PJM. The new entrant CT energy market net revenue results must therefore be interpreted carefully when comparing to existing CTs which are generally smaller and less efficient than the newest CT technology used by the new entrant CT.

New entrant CT plant energy market net revenues were higher across all zones except Met-Ed, PECO, and PSEG in 2018 than in 2017 (Table 7-9). The increase in energy prices more than offset the increase in gas prices except in these zones. Gas pipelines have been updated to reflect the most commonly used pipeline within the zone.

Table 7-9 Energy net revenue for a new entrant gas fired CT under economic dispatch: 2014 through 2018 (Dollars per installed MW-year)[19 20]

Zone	2014	2015	2016	2017	2018	Change in 2018 from 2017
AECO	$85,559	$53,906	$56,536	$32,852	$39,081	19%
AEP	$75,204	$70,174	$59,142	$39,723	$76,771	93%
APS	$100,254	$98,446	$65,715	$52,164	$76,110	46%
ATSI	$57,789	$60,807	$56,841	$42,410	$90,859	114%
BGE	$103,414	$84,034	$100,287	$45,242	$57,853	28%
ComEd	$38,012	$34,632	$37,422	$25,323	$36,620	45%
DAY	$52,492	$58,641	$55,345	$41,048	$85,337	108%
DEOK	$47,627	$56,302	$52,460	$39,499	$93,272	136%
DLCO	$54,731	$82,980	$76,646	$50,270	$62,740	25%
Dominion	$70,238	$71,643	$68,491	$41,336	$62,186	50%
DPL	$69,612	$39,809	$31,144	$24,901	$34,599	39%
EKPC	$66,059	$57,460	$51,507	$33,067	$58,944	78%
JCPL	$86,167	$51,989	$51,683	$36,336	$36,470	0%
Met-Ed	$88,304	$90,038	$75,322	$59,639	$49,038	(18%)
PECO	$90,605	$88,281	$70,435	$50,485	$42,762	(15%)
PENELEC	$135,004	$140,985	$93,894	$67,089	$87,635	31%
Pepco	$76,271	$55,534	$52,356	$30,641	$47,502	55%
PPL	$203,674	$156,556	$76,508	$62,547	$85,407	37%
PSEG	$108,183	$101,094	$76,120	$58,726	$48,683	(17%)
RECO	$82,044	$59,293	$57,561	$38,818	$39,194	1%
PJM	$58,381	$75,630	$63,271	$43,606	$60,553	39%

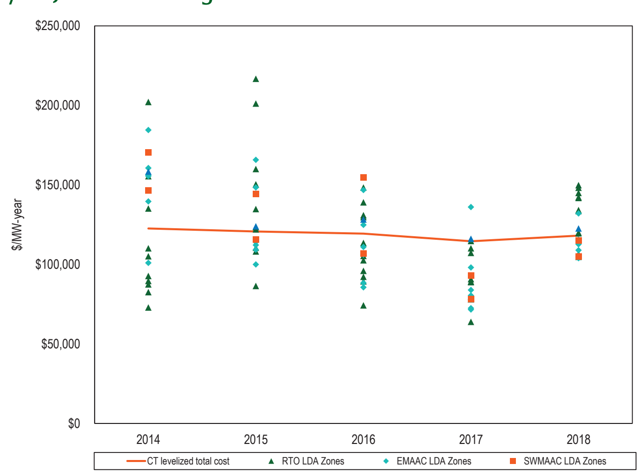
In 2018, a new CT would have received sufficient net revenue to cover levelized total costs in eleven zones and would have covered more than 87 percent of levelized costs in all zones as a result of higher energy prices and higher locational capacity market prices (Table 7-10). At 88 percent, the new CT would cover all avoidable costs and earn a positive but lower rate of return.

Table 7-10 Percent of 20-year levelized total costs recovered by CT energy and capacity net revenue: 2014 through 2018

Zone	2014	2015	2016	2017	2018
AECO	127%	94%	93%	70%	92%
AEP	90%	101%	80%	68%	114%
APS	110%	125%	86%	79%	113%
ATSI	76%	133%	116%	78%	125%
BGE	139%	119%	130%	81%	97%
ComEd	59%	72%	62%	56%	89%
DAY	71%	92%	77%	69%	120%
DEOK	67%	90%	75%	68%	127%
DLCO	73%	112%	95%	78%	102%
Dominion	86%	102%	88%	70%	101%
DPL	114%	83%	72%	63%	88%
EKPC	82%	91%	74%	62%	98%
JCPL	127%	93%	89%	73%	89%
Met-Ed	127%	124%	109%	94%	90%
PECO	131%	123%	105%	86%	95%
PENELEC	165%	167%	124%	100%	123%
Pepco	120%	96%	89%	68%	89%
PPL	221%	180%	110%	96%	120%
PSEG	150%	137%	123%	119%	112%
RECO	129%	103%	107%	101%	104%
PJM	88%	111%	97%	81%	104%

Figure 7-6 shows zonal net revenue and the annual levelized total cost for the new entrant CT by LDA.

Figure 7-6 New entrant CT net revenue and 20-year levelized total cost by LDA (Dollars per installed MW-year): 2014 through 2018



19 The energy net revenues presented for the PJM area in this section represent the zonal average energy net revenues.

20 Energy net revenues presented for 2018 have been updated since the 2017 State of the Market Report for a one CT configuration and updated gas pipelines.

New Entrant Combined Cycle

Energy market net revenue was calculated for a new CC plant economically dispatched by PJM. It was assumed that the CC plant had a minimum run time of four hours. The unit was first committed day ahead in profitable blocks of at least four hours, including start costs.[21] If the unit was not already committed day ahead, it was run in real time in standalone profitable blocks of at least four hours, or any profitable hours bordering the profitable day-ahead or real-time block.

New entrant CC plant energy market net revenues were higher in all zones in 2018 than in 2017 (Table 7-11). The increase in energy prices offset the increase in gas prices. Gas pipelines have been updated to reflect the most commonly used pipeline within the zone.

Table 7-11 Energy net revenue for a new entrant CC under economic dispatch: 2014 through 2018 (Dollars per installed MW-year)[22]

Zone	2014	2015	2016	2017	2018	Change in 2018 from 2017
AECO	$145,019	$86,041	$77,436	$56,881	$75,553	33%
AEP	$122,938	$110,129	$87,008	$67,312	$121,414	80%
APS	$173,881	$159,605	$111,871	$86,244	$130,397	51%
ATSI	$95,226	$100,101	$84,691	$68,957	$134,358	95%
BGE	$178,861	$144,276	$147,033	$81,053	$110,097	36%
ComEd	$56,376	$62,091	$60,623	$43,655	$63,154	45%
DAY	$87,647	$98,713	$84,056	$69,165	$130,403	89%
DEOK	$76,708	$93,987	$79,855	$65,472	$135,931	108%
DLCO	$95,715	$110,504	$98,949	$73,380	$102,504	40%
Dominion	$121,923	$113,425	$98,902	$68,916	$103,559	50%
DPL	$125,605	$59,502	$50,853	$32,376	$55,107	70%
EKPC	$106,766	$96,164	$77,905	$59,573	$101,444	70%
JCPL	$148,884	$84,893	$72,755	$60,433	$72,751	20%
Met-Ed	$143,346	$119,387	$93,883	$81,360	$87,971	8%
PECO	$148,203	$119,922	$88,690	$73,232	$83,034	13%
PENELEC	$199,981	$167,584	$113,286	$88,862	$131,738	48%
Pepco	$133,442	$110,841	$97,806	$61,656	$94,278	53%
PPL	$261,970	$176,376	$95,223	$83,342	$121,142	45%
PSEG	$178,093	$135,601	$95,446	$81,765	$91,104	11%
RECO	$144,256	$92,028	$77,966	$62,871	$75,043	19%
PJM	$100,026	$112,059	$89,712	$68,325	$101,049	48%

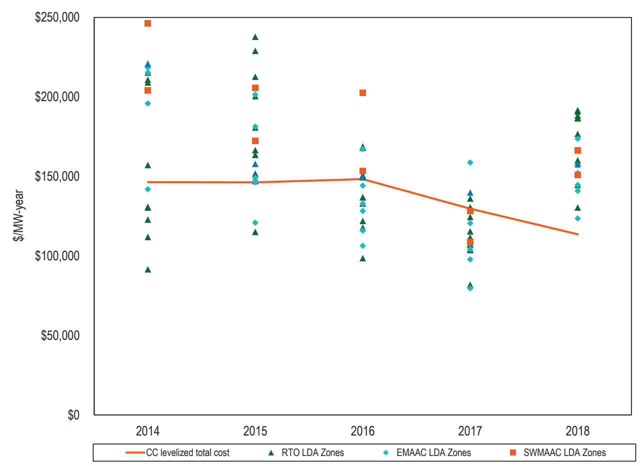
In 2018, a new CC would have received sufficient net revenue to cover levelized total costs in all zones (Table 7-12).

Table 7-12 Percent of 20-year levelized total costs recovered by CC energy and capacity net revenue: 2014 through 2018

Zone	2014	2015	2016	2017	2018
AECO	147%	101%	90%	80%	127%
AEP	108%	112%	84%	81%	157%
APS	143%	145%	101%	96%	165%
ATSI	89%	137%	113%	89%	168%
BGE	168%	141%	137%	99%	146%
ComEd	63%	79%	66%	63%	115%
DAY	84%	104%	82%	83%	164%
DEOK	76%	100%	79%	80%	169%
DLCO	89%	112%	92%	86%	140%
Dominion	107%	114%	92%	83%	141%
DPL	134%	83%	72%	61%	109%
EKPC	97%	102%	78%	75%	138%
JCPL	150%	100%	86%	83%	124%
Met-Ed	144%	124%	101%	99%	127%
PECO	149%	124%	97%	93%	134%
PENELEC	183%	156%	114%	105%	166%
Pepco	139%	118%	103%	84%	133%
PPL	225%	162%	102%	101%	155%
PSEG	174%	138%	113%	122%	153%
RECO	151%	108%	101%	108%	139%
PJM	103%	117%	96%	90%	143%

Figure 7-7 shows zonal net revenue and the annual levelized total cost for the new entrant CC by LDA.

Figure 7-7 New entrant CC net revenue and 20-year levelized total cost by LDA (Dollars per installed MW-year): 2009 through 2018



21 All starts associated with combined cycle units are assumed to be warm starts.
22 The energy net revenues presented for the PJM area in this section represent the zonal average energy net revenues.

New Entrant Coal Plant

Energy market net revenue was calculated for a new CP plant economically dispatched by PJM. It was assumed that the CP plant had a minimum run time of eight hours. The unit was first committed day ahead in profitable blocks of at least eight hours, including start costs. If the unit was not already committed day-ahead, it was run in real time in standalone profitable blocks of at least eight hours, or any profitable hours bordering the profitable day-ahead or real-time block.

New entrant CP plant energy market net revenues were higher in all zones as a result of more run hours, higher gas prices and associated higher energy prices (Table 7-13).

Table 7-13 Energy net revenue for a new entrant CP: 2014 through 2018 (Dollars per installed MW-year)[23]

Zone	2014	2015	2016	2017	2018	Change in 2018 from 2017
AECO	$135,618	$57,738	$13,467	$9,372	$40,456	332%
AEP	$131,376	$59,291	$45,026	$41,987	$77,378	84%
APS	$122,804	$50,615	$18,633	$21,504	$53,394	148%
ATSI	$144,617	$60,042	$40,157	$42,021	$80,156	91%
BGE	$194,930	$98,895	$55,337	$24,037	$63,302	163%
ComEd	$130,840	$46,034	$33,781	$31,360	$45,189	44%
DAY	$136,357	$58,151	$36,942	$40,631	$75,823	87%
DEOK	$123,148	$53,572	$33,432	$37,064	$81,646	120%
DLCO	$114,884	$46,956	$35,006	$38,052	$79,622	109%
Dominion	$181,512	$104,919	$52,227	$32,934	$78,999	140%
DPL	$194,835	$85,228	$26,882	$20,957	$64,206	206%
EKPC	$118,789	$44,408	$28,752	$29,718	$52,381	76%
JCPL	$140,056	$55,433	$10,206	$10,469	$39,241	275%
Met-Ed	$178,817	$75,694	$23,786	$25,032	$61,234	145%
PECO	$129,947	$53,073	$10,853	$9,537	$37,622	294%
PENELEC	$150,457	$69,447	$27,272	$19,963	$56,293	182%
Pepco	$134,680	$51,598	$15,734	$8,585	$37,456	336%
PPL	$129,001	$51,990	$9,195	$9,699	$37,347	285%
PSEG	$202,692	$84,772	$16,581	$15,876	$45,705	188%
RECO	$198,435	$84,885	$16,104	$15,229	$46,115	203%
PJM	$155,324	$64,637	$27,469	$24,201	$57,678	138%

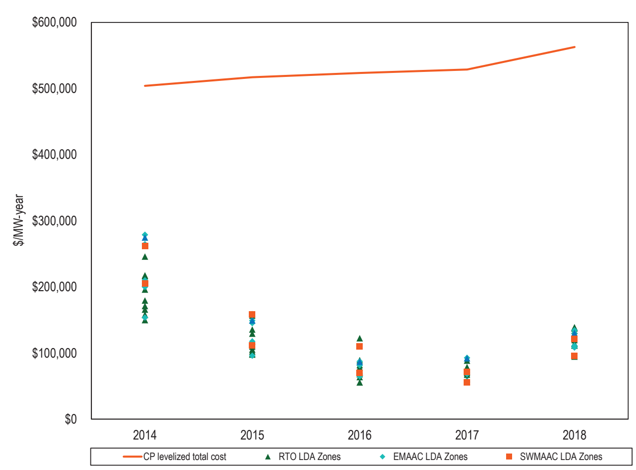
In 2018, a new CP would not have received sufficient net revenue to cover levelized total costs in any zone (Table 7-14). This has been the consistent result for a new CP for the entire five year period of the analysis.

Table 7-14 Percent of 20-year levelized total costs recovered by CP energy and capacity net revenue: 2014 through 2017

Zone	2014	2015	2016	2017	2018
AECO	41%	23%	13%	11%	20%
AEP	33%	21%	16%	15%	24%
APS	31%	20%	11%	11%	20%
ATSI	36%	31%	23%	17%	25%
BGE	52%	31%	21%	13%	22%
ComEd	33%	19%	13%	13%	20%
DAY	34%	21%	14%	15%	24%
DEOK	31%	20%	13%	14%	25%
DLCO	30%	19%	14%	14%	24%
Dominion	43%	30%	17%	13%	24%
DPL	52%	28%	16%	13%	24%
EKPC	30%	19%	13%	13%	19%
JCPL	42%	22%	12%	11%	19%
Met-Ed	49%	26%	15%	14%	21%
PECO	40%	22%	12%	11%	19%
PENELEC	43%	25%	16%	13%	20%
Pepco	41%	22%	13%	11%	17%
PPL	39%	22%	12%	11%	17%
PSEG	55%	29%	17%	18%	23%
RECO	54%	29%	17%	17%	23%
PJM	41%	24%	15%	14%	22%

Figure 7-8 shows zonal net revenue and the annual levelized total cost for the new entrant CP by LDA.

Figure 7-8 New entrant CP net revenue and 20-year levelized total cost by LDA (Dollars per installed MW-year): 2014 through 2018



23 The energy net revenues presented for the PJM area in this section represent the zonal average energy net revenues.

New Entrant Nuclear Plant

Energy market net revenue was calculated assuming that the nuclear plant was dispatched day ahead by PJM for all available plant hours. The unit runs for all hours but output reflects the class average capacity factor.[24]

New entrant nuclear plant energy market net revenues were higher in all zones as a result of higher gas prices and associated higher energy prices (Table 7-15).

Table 7-15 Energy net revenue for a new entrant nuclear plant: 2014 through 2018 (Dollars per installed MW-year)[25]

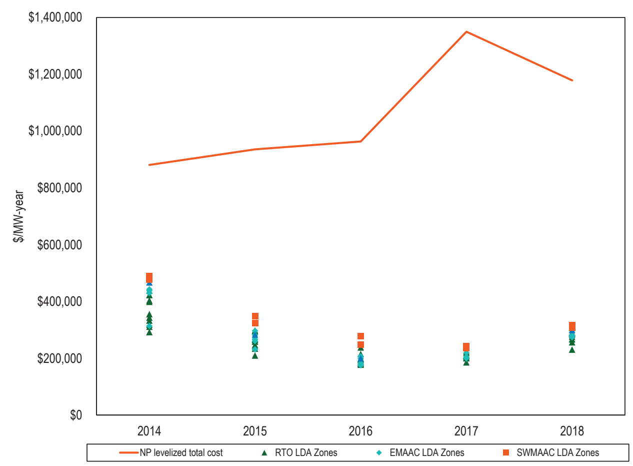
Zone	2014	2015	2016	2017	2018	Change in 2018 from 2017
AECO	$371,704	$210,951	$131,601	$156,342	$215,981	38%
AEP	$298,580	$196,283	$157,896	$171,019	$222,186	30%
APS	$323,903	$219,518	$162,740	$175,029	$233,849	34%
ATSI	$311,864	$199,801	$159,236	$176,249	$236,039	34%
BGE	$425,852	$291,608	$226,774	$198,271	$263,053	33%
ComEd	$260,958	$161,560	$144,334	$150,715	$166,306	10%
DAY	$301,626	$198,297	$159,007	$176,383	$232,332	32%
DEOK	$287,128	$193,109	$154,639	$172,138	$237,909	38%
DLCO	$279,720	$185,821	$153,346	$171,689	$235,049	37%
Dominion	$372,061	$249,796	$181,090	$189,531	$254,873	34%
DPL	$410,148	$239,877	$155,841	$175,178	$245,078	40%
EKPC	$282,325	$183,084	$149,713	$163,766	$205,510	25%
JCPL	$376,070	$209,466	$126,740	$160,983	$213,276	32%
Met-Ed	$358,792	$202,324	$129,738	$166,160	$213,557	29%
PECO	$363,090	$203,906	$124,425	$156,285	$208,282	33%
PENELEC	$335,356	$208,193	$146,528	$166,415	$222,108	33%
Pepco	$409,787	$267,502	$197,183	$192,440	$254,757	32%
PPL	$359,322	$202,890	$126,268	$157,925	$203,791	29%
PSEG	$399,029	$220,799	$131,275	$166,621	$217,635	31%
RECO	$394,147	$222,479	$132,357	$167,355	$219,857	31%
PJM	$346,073	$213,363	$152,537	$170,525	$225,071	32%

In 2018, a new nuclear plant would not have received sufficient net revenue to cover levelized total costs in any zone (Table 7-16). This has been the consistent result for a new nuclear plant for the entire five year period of the analysis.

Table 7-16 Percent of 20-year levelized total costs recovered by nuclear energy and capacity net revenue: 2014 through 2018

Zone	2014	2015	2016	2017	2018
AECO	50%	29%	19%	15%	24%
AEP	37%	26%	20%	15%	23%
APS	40%	29%	20%	16%	24%
ATSI	39%	32%	25%	16%	25%
BGE	56%	37%	29%	18%	27%
ComEd	33%	22%	18%	14%	20%
DAY	38%	26%	20%	16%	24%
DEOK	36%	26%	20%	15%	25%
DLCO	35%	25%	19%	15%	24%
Dominion	46%	32%	22%	17%	26%
DPL	54%	32%	21%	16%	26%
EKPC	36%	25%	19%	15%	22%
JCPL	50%	28%	18%	15%	24%
Met-Ed	48%	28%	19%	16%	23%
PECO	49%	28%	18%	15%	23%
PENELEC	45%	28%	21%	16%	23%
Pepco	54%	35%	26%	17%	26%
PPL	48%	28%	18%	15%	22%
PSEG	54%	30%	21%	18%	25%
RECO	53%	30%	21%	18%	25%
PJM	45%	29%	21%	16%	24%

Figure 7-9 New entrant NP net revenue and 20-year levelized total cost by LDA (Dollars per installed MW-year): 2014 through 2018



24 The annual class average capacity factor was applied to total energy market net revenues.
25 The energy net revenues presented for the PJM area in this section represent the zonal average energy net revenues.

New Entrant Diesel

Energy market net revenue was calculated for a DS plant economically dispatched by PJM in real time.

New entrant DS plant energy market net revenues were higher in all zones except ComEd in 2018 (Table 7-17).

Table 7-17 Energy market net revenue for a new entrant DS: 2014 through 2018 (Dollars per installed MW-year)

Zone	2014	2015	2016	2017	2018	Change in 2018 from 2017
AECO	$33,704	$13,206	$2,347	$2,524	$10,603	320%
AEP	$14,731	$3,910	$950	$1,406	$4,240	201%
APS	$18,335	$7,390	$1,001	$1,327	$6,833	415%
ATSI	$14,366	$3,615	$2,054	$1,754	$7,378	321%
BGE	$51,010	$18,278	$8,113	$3,156	$13,132	316%
ComEd	$11,523	$2,284	$716	$1,325	$735	(45%)
DAY	$14,546	$3,699	$1,009	$1,656	$4,009	142%
DEOK	$13,708	$3,226	$1,376	$3,054	$6,809	123%
DLCO	$13,365	$3,113	$2,381	$1,499	$9,476	532%
Dominion	$43,399	$12,028	$2,488	$2,727	$15,543	470%
DPL	$39,134	$20,042	$3,638	$5,599	$14,648	162%
EKPC	$14,745	$2,915	$998	$961	$1,940	102%
JCPL	$33,656	$13,100	$883	$2,809	$11,464	308%
Met-Ed	$32,564	$13,084	$857	$3,755	$11,301	201%
PECO	$32,940	$12,493	$831	$2,810	$10,119	260%
PENELEC	$16,243	$6,428	$864	$1,674	$5,658	238%
Pepco	$52,350	$12,827	$3,424	$2,466	$12,714	416%
PPL	$33,521	$13,135	$756	$2,959	$9,039	205%
PSEG	$33,121	$12,688	$1,013	$3,243	$10,623	228%
RECO	$31,237	$13,751	$1,195	$2,991	$9,964	233%
PJM	$29,787	$9,561	$1,845	$2,485	$8,811	255%

In 2018, the new entrant DS would not have received sufficient net revenue to cover levelized total costs in any zone. This has been the consistent result for a new DS for the entire five year period of the analysis.

Table 7-18 Percent of 20-year levelized total costs recovered by DS energy and capacity net revenue: 2014 through 2018

Zone	2014	2015	2016	2017	2018
AECO	62%	41%	31%	29%	49%
AEP	28%	31%	20%	23%	37%
APS	31%	33%	20%	23%	39%
ATSI	28%	58%	47%	28%	39%
BGE	71%	44%	34%	29%	43%
ComEd	26%	30%	20%	23%	42%
DAY	28%	30%	20%	23%	37%
DEOK	28%	30%	20%	24%	38%
DLCO	28%	30%	21%	23%	40%
Dominion	46%	35%	21%	24%	44%
DPL	65%	45%	32%	31%	52%
EKPC	28%	30%	20%	22%	35%
JCPL	62%	41%	30%	29%	49%
Met-Ed	59%	41%	30%	30%	42%
PECO	61%	40%	30%	29%	49%
PENELEC	49%	37%	30%	29%	38%
Pepco	73%	41%	31%	29%	43%
PPL	60%	41%	30%	29%	40%
PSEG	65%	43%	39%	48%	58%
RECO	64%	44%	40%	48%	58%
PJM	47%	38%	29%	30%	43%

New Entrant On Shore Wind Installation

Energy market net revenues for a wind installation were calculated hourly assuming the unit generated at the average capacity factor of operating wind units in the zone if 75 percent of existing wind units in the zone were generating at greater than or equal to 25 percent capacity factor in that hour. The unit is credited with wind RECs for its generation and is assumed to have taken a 1603 payment instead of either the Investment Tax Credit (ITC) or Production Tax Credit (PTC).[26]

On shore wind energy market net revenues were higher in 2018 as a result of higher energy prices.

Table 7-19 Energy market net revenue for an on shore wind installation (Dollars per installed MW-year): 2014 through 2018

Zone	2014	2015	2016	2017	2018	Change in 2018 from 2017
AEP	$114,239	$80,178	$67,159	$70,717	$92,230	30%
APS	$102,906	$71,775	$62,440	$73,390	$95,929	31%
ComEd	$108,057	$81,422	$69,030	$74,787	$76,434	2%
PENELEC	$125,968	$82,392	$63,565	$72,304	$96,112	33%

Renewable energy credits ranged from 30 percent of the total net revenue of an on shore wind installation in APS to 38 percent of the total net revenue of an on shore wind installation in ComEd.

26 The 1603 payment is a direct payment of 30 percent of the project cost.

Table 7-20 RECs revenue for an on shore wind installation (Dollars per installed MW-year): 2014 through 2018

Zone	2014	2015	2016	2017	2018
AEP	$35,452	$40,709	$42,605	$44,740	$44,969
APS	$31,597	$31,921	$37,846	$44,409	$45,010
ComEd	$41,769	$48,128	$47,995	$52,940	$52,075
PENELEC	$35,598	$36,773	$41,347	$44,891	$45,880

In 2018, a new on shore wind installation would not have received sufficient net revenue to cover levelized total costs in any of the four zones analyzed. This has been the consistent result for a new wind installation for the entire five year period of the analysis. Renewable energy credits accounted for between 30 percent of the total net revenue of a wind installation in APS and 38 percent of the total net revenue of a wind installation in ComEd.

Table 7-21 Percent of 20-year levelized total costs recovered by on shore wind net revenue (Dollars per installed MW-year): 2014 through 2018

Zone	2014	2015	2016	2017	2018
AEP	78%	63%	49%	64%	67%
APS	70%	54%	45%	65%	69%
ComEd	78%	67%	52%	70%	64%
PENELEC	86%	62%	48%	65%	69%

New Entrant Off Shore Wind Installation

Energy market net revenues for an off shore wind installation were calculated by assuming the unit received the average annual zonal RT LMP and operated at a 45 percent capacity factor. The unit is credited with wind RECs for its generation and is assumed to have taken a 1603 payment instead of either the Investment Tax Credit (ITC) or Production Tax Credit (PTC).

Off shore wind energy market net revenues were higher in 2018 than 2017 as a result of higher energy prices.

Table 7-22 Energy market net revenue for an off shore wind installation (Dollars per installed MW-year): 2014 through 2018

Zone	2014	2015	2016	2017	2018	Change in 2018 from 2017
AECO	$201,681	$136,886	$102,884	$115,326	$145,738	26%

Renewable energy credits accounted for 31 percent of the total net revenue of an off shore wind installation.

Table 7-23 RECs revenue for an off shore wind installation (Dollars per installed MW-year): 2014 through 2018

Zone	2014	2015	2016	2017	2018
AECO	$55,002	$60,009	$64,741	$68,446	$69,916

In 2018, a new off shore wind installation would not have received sufficient net revenue to cover levelized total costs.

Table 7-24 Percent of 20-year levelized total costs recovered by off shore wind net revenue (Dollars per installed MW-year): 2014 through 2018

Zone	2014	2015	2016	2017	2018
AECO	40%	30%	25%	28%	33%

New Entrant Solar Installation

Energy market net revenues for a solar installation were calculated hourly assuming the unit was generating at the average hourly capacity factor of operating solar units in the zone if 75 percent of existing solar units in the zone were generating at greater than or equal to 25 percent capacity factor in that hour. The unit is credited with SRECs for its generation and is assumed to have taken a 1603 payment instead of either the Investment Tax Credit (ITC) or Production Tax Credit (PTC).[27]

Solar energy market net revenues were higher in 2018 as a result of higher energy prices.

Table 7-25 Energy market net revenue for a solar installation (Dollars per installed MW-year): 2014 through 2018

Zone	2014	2015	2016	2017	2018	Change in 2018 from 2017
AECO	$52,811	$40,145	$33,903	$32,591	$35,636	9%
Dominion	-	-	$68,474	$62,385	$67,774	9%
DPL	-	-	$39,785	$40,312	$49,960	24%
JCPL	$48,418	$32,538	$27,391	$27,698	$28,511	3%
PSEG	$68,093	$53,282	$38,566	$36,803	$38,380	4%

Renewable energy credits ranged from 64 percent of the total net revenue of a solar installation in DPL to 78 percent of the total net revenue of a solar installation in AECO.

27 The 1603 payment is a direct payment of 30 percent of the project cost.

Table 7-26 RECs revenue for a solar installation (Dollars per installed MW-year): 2014 through 2018

Zone	2014	2015	2016	2017	2018
AECO	$169,543	$221,495	$250,090	$250,546	$219,959
Dominion	-	-	$281,175	$221,189	$167,697
DPL	-	-	$175,753	$160,133	$135,394
JCPL	$160,696	$185,595	$204,688	$207,605	$181,659
PSEG	$212,050	$275,223	$286,233	$272,447	$232,241

In 2018, a new solar installation would have received sufficient net revenue to cover levelized total costs in AECO, Dominion, JCPL and PSEG.

Table 7-27 Percent of 20-year levelized total costs recovered by solar net revenue (Dollars per installed MW-year): 2014 through 2018

Zone	2014	2015	2016	2017	2018
AECO	105%	121%	139%	149%	121%
Dominion	-	-	165%	148%	110%
DPL	-	-	107%	108%	90%
JCPL	99%	102%	115%	125%	101%
PSEG	130%	150%	160%	168%	129%

Historical New Entrant CT and CC Revenue Adequacy

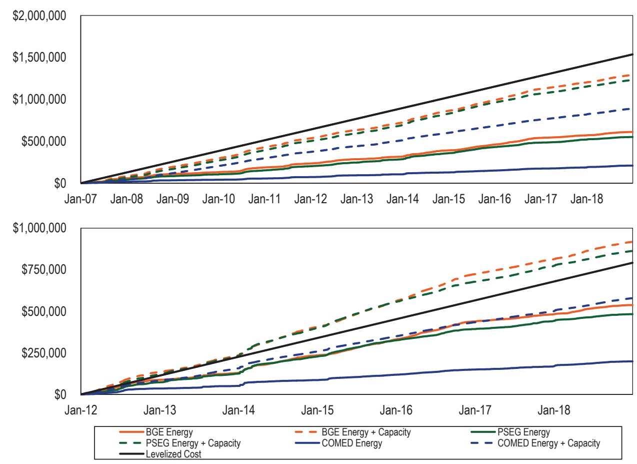
Total unit net revenues include energy and capacity revenues. Analysis of the total unit revenues of theoretical new entrant CTs and CCs for three representative locations shows that CT and CC units that entered the PJM markets in 2007 have not covered their total costs, including the return on and of capital, on a cumulative basis. The analysis also shows that theoretical new entrant CTs and CCs that entered the PJM markets in 2012 have covered their total costs on a cumulative basis in the eastern PSEG and BGE zones but have not covered total costs in the western ComEd Zone. Energy market revenues alone were not sufficient to cover total costs in any scenario, which demonstrates the critical role of the capacity market revenue in covering total costs.

Under cost of service regulation, units are guaranteed that they will cover their total costs, assuming that the costs were determined to be reasonable. To the extent that units built in the PJM markets did not cover their total costs, investors were worse off and customers were better off than under cost of service regulation.

The summary figures compare net revenues for a new entrant CT and CC that began operation on January 1, 2007, at the start of the RPM Capacity Market, and new entrant CT and CC that began operation on January 1, 2012. In each figure, the solid black line shows the total net revenue required to cover total costs. The solid colored lines show net energy revenue by zone. The dashed colored lines show the sum of net energy and capacity revenue by zone.

For the ComEd Zone, the PSEG Zone and the BGE Zone, Figure 7-10 compares cumulative energy market net revenues and energy market net revenues plus capacity market revenues to cumulative levelized costs for a new CT that began operation on January 1, 2007, and for a new CT that began operation on January 1, 2012. Cumulative energy and capacity market net revenues were less than cumulative total costs of the 2007 new entrant. Cumulative energy and capacity market net revenues were greater than the cumulative total costs of the 2012 new entrant CT unit in BGE and PSEG zones and less than total costs for the ComEd Zone.

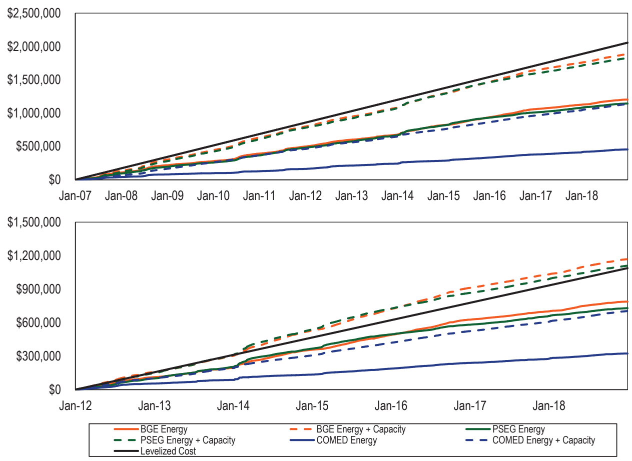
Figure 7-10 Historical new entrant CT revenue adequacy: January 2007 through December 2018 and January 2012 through December 2018[28]



28 The gas pipeline pricing point used in this analysis for ComEd remains Chicago City Gate. The gas pipelines used in this analysis have been updated to Zone 6 non-NY for BGE and Texas Eastern M3 for PSEG.

For the ComEd Zone, the PSEG Zone and the BGE Zone, Figure 7-11 compares cumulative energy market net revenues and energy market net revenues plus capacity market revenues to cumulative levelized costs for a new CC that began operation on January 1, 2007, and for a new CC that began operation on January 1, 2012. Cumulative energy and capacity market net revenues were greater than the cumulative total costs of the 2012 new entrant CC unit in BGE and PSEG zones and less than total costs for the 2007 and 2012 new entrant CC in ComEd Zone. Energy market revenues alone were not sufficient to cover total costs in any scenario, which demonstrates the critical role of the capacity market revenue in covering total costs.

Figure 7-11 Historical new entrant CC revenue adequacy: January 2007 through December 2018 and January 2012 through December 2018[29]



Assumptions used for this analysis are shown in Table 7-28.

Table 7-28 Assumptions for analysis of new entry in 2007 and 2012

	2007 CT	2012 CT	2007 CC	2012 CC
Project Cost CT	$311,737,000	$319,167,000	$658,598,000	$665,995,000
Fixed O&M ($/MW-Year)	$14,475	$14,628	$20,016	$20,126
End of Life Value	$0	$0	$0	$0
Loan Term	20 years	20 years	20 years	20 years
Percent Equity (%)	50%	50%	50%	50%
Percent Debt (%)	50%	50%	50%	50%
Loan Interest Rate (%)	7%	7%	7%	7%
Federal Income Tax Rate (%)	35%	35%	35%	35%
State Income Tax Rate (%)	9%	9%	9%	9%
General Escalation (%)	2.5%	2.5%	2.5%	2.5%
Technology	GE Frame 7FA.04	GE Frame 7FA.05	GE Frame 7FA.04	GE Frame 7FA.05
ICAP (MW)	336	410	601	655
Depreciation MACRS 150% declining balance	15 years	15 years	20 years	20 years

Factors in Net Revenue Adequacy

Although it can be expected that in the long run, in a competitive market, net revenue from all sources will cover the fixed and variable costs of investing in new generating resources, including a competitive return on investment, actual results are expected to vary from year to year. Wholesale energy markets, like other markets, are cyclical. When the markets are long, prices will be lower and when the markets are short, prices will be higher.

The net revenue for a new generation resource varied significantly with the input fuel type and the efficiency of the reference technology. In 2018, the average short run marginal cost of the CC was lower than the average short run

29 The gas pipeline pricing point used in this analysis for ComEd remains Chicago City Gate. The gas pipelines used in this analysis have been updated to Zone 6 non-NY for BGE and Texas Eastern M3 for PSEG.

marginal cost of the CP in every month except January and the operating cost of the CT was lower than the CP all months except January, November, and December. (Figure 7-5)

The net revenue results illustrate some fundamentals of the PJM wholesale power market. Higher energy prices, higher gas prices, and higher coal prices meant that all units ran for more hours with higher margins than in prior years. High demand hours result in less efficient units setting prices, which results in higher net revenues for more efficient units. Scarcity revenues in the energy market also contribute to covering fixed costs, when they occur, but scarcity revenues are not a predictable and systematic source of net revenue in the PJM design. In the PJM design, the balance of the net revenue required to cover the fixed costs of peaking units comes from the capacity market.

However, there may be a lag in capacity market prices which either offsets the reduction in energy market revenues or exacerbates the reduction in energy market revenues. Capacity market prices are a function of a three year historical average net revenue offset which is generally an inaccurate estimate of actual net revenues in the current operating year and an inaccurate estimate of expected net revenues for the forward capacity market. A forward looking estimate of expected energy and ancillary services net revenues is a preferred method for defining the offset in the capacity market. Capacity market prices and revenues have a substantial impact on the profitability of investing in CTs and CCs. In 2018, capacity market prices increased in all zones.

The returns earned by investors in generating units are a direct function of net revenues, the cost of capital, and the fixed costs associated with the generating unit. Positive returns may be earned at less than the annualized fixed costs, although the returns are less than the target. A sensitivity analysis was performed to determine the impact of changes in net revenue on the return on investment for a new generating unit. The internal rate of return (IRR) was calculated for a range of 20-year levelized net revenue streams, using 20-year levelized total costs from Table 7-7 . The results are shown in Table 7-29.[30]

Table 7-29 Internal rate of return sensitivity for CT, CC and CP generators

	CT		CC		CP	
	20-Year Levelized Net Revenue	20-Year After Tax IRR	20-Year Levelized Net Revenue	20-Year After Tax IRR	20-Year Levelized Net Revenue	20-Year After Tax IRR
Sensitivity 1	$124,974	13.5%	$119,116	13.5%	$598,944	13.3%
Base Case	$121,324	12.0%	$113,641	12.0%	$562,444	12.0%
Sensitivity 2	$117,674	10.4%	$108,166	10.4%	$525,944	10.6%
Sensitivity 3	$114,024	8.6%	$102,691	8.6%	$489,444	9.0%
Sensitivity 4	$110,374	6.5%	$97,216	6.6%	$452,944	7.2%
Sensitivity 5	$106,724	4.0%	$91,741	4.2%	$416,444	5.1%
Sensitivity 6	$103,074	0.8%	$86,266	1.1%	$379,944	2.3%

Additional sensitivity analyses were performed for the CT and the CC technologies for the debt to equity ratio; the term of the debt financing; and the costs of interconnection. Table 7-30 shows the levelized annual revenue requirements associated with a range of debt to equity ratios holding the 12 percent IRR constant. The base case assumes 50/50 debt to equity ratio. As the percent of equity financing decreases, the levelized annual revenue required to earn a 12 percent IRR falls.

Table 7-30 Debt to equity ratio sensitivity for CT and CC assuming 20 year debt term and 12 percent internal rate of return

	Equity as a percent of total financing	CT levelized annual revenue requirement	CC levelized annual revenue requirement
Sensitivity 1	60%	$126,862	$120,515
Sensitivity 2	55%	$124,082	$117,056
Base Case	50%	$121,324	$113,641
Sensitivity 3	45%	$118,586	$110,270
Sensitivity 4	40%	$115,870	$106,942
Sensitivity 5	35%	$113,174	$103,659
Sensitivity 6	30%	$110,500	$100,418

Table 7-31 shows the levelized annual revenue requirement associated with various terms for the debt financing, assuming a 50/50 debt to equity ratio and 12 percent rate of return. As the term of the debt financing decreases, more net revenue is required annually to maintain a 12 percent rate of return.

30 This analysis was performed for the MMU by Pasteris Energy, Inc. The annual costs were based on a 20-year project life, 50/50 debt to equity capital structure with a target IRR of 12 percent and a debt rate of 7 percent. For depreciation, the analysis assumed a 15-year modified accelerated cost-recovery schedule (MACRS) for the CT plant and 20-year MACRS for the CC and CP plants. An annual rate of cost inflation of 2.5 percent was used in all calculations.

Table 7-31 Debt term sensitivity for CT and CC assuming 50/50 debt to equity ratio and 12 percent internal rate of return

	Term of debt in years	CT levelized annual revenue requirement	CC levelized annual revenue requirement
Sensitivity 1	30	$112,990	$120,347
Sensitivity 2	25	$116,144	$116,914
Base Case	20	$121,324	$113,641
Sensitivity 3	15	$125,442	$110,531
Sensitivity 4	10	$130,904	$107,587

Table 7-32 shows the impact of a range of assumed interconnection costs on the levelized annual revenue requirement for the CT and the CC technologies. Interconnection costs vary significantly by location across PJM and even within PJM zones and can significantly impact the profitability of investing in peaking and midmerit generation technologies in a specific location. The impact on the annualized revenue requirements is more substantial for CTs than for CCs as interconnection costs are a larger proportion of overall project costs for CTs and as the new entrant CC has a higher energy output over which to spread the costs than the new entrant CT.

Table 7-32 Interconnection cost sensitivity for CT and CC

	CT			CC		
	Capital cost ($000)	Percent of total capital cost	Annualized revenue requirement ($/ICAP-Year)	Capital cost ($000)	Percent of total capital cost	Annualized revenue requirement ($/ICAP-Year)
Sensitivity 1	$0	0.0%	$119,079	$0	0.0%	$111,230
Sensitivity 2	$3,501	1.3%	$120,201	$11,056	1.2%	$112,436
Base Case	$7,001	2.6%	$121,324	$22,113	2.3%	$113,641
Sensitivity 3	$10,502	3.9%	$122,446	$33,169	3.5%	$114,847
Sensitivity 4	$14,003	5.2%	$123,568	$44,225	4.6%	$116,052
Sensitivity 5	$17,503	6.6%	$124,691	$55,281	5.8%	$117,257
Sensitivity 6	$21,004	7.9%	$125,793	$66,338	7.0%	$118,463

Actual Net Revenue

This analysis of net revenues is based on actual net revenues for actual units operating in PJM. Net revenues from energy and capacity markets are compared to avoidable costs to determine the extent to which the revenues from PJM markets provide sufficient incentive for continued operations in PJM markets. Avoidable costs are the costs which must be paid each year in order to keep a unit operating. Avoidable costs are less than total costs, which include the return on and of capital, and more than marginal costs, which are the purely short run incremental costs of producing energy. It is rational to operate a unit whenever the price is greater than its short run marginal costs. It is rational for an owner to continue to operate a unit rather than retire the unit if the unit is covering or is expected to cover its avoidable costs and therefore contributing to covering fixed costs. It is not rational for an owner to continue to operate a unit rather than retire the unit if the unit is not covering and is not expected to cover its avoidable costs. As a general matter, under those conditions, retirement of the unit is the logical option. Thus, this comparison of actual net revenues to avoidable costs is a measure of the extent to which units in PJM may be at risk of retirement.

The definition of avoidable costs, based on the RPM rules, includes both avoidable costs and the annualized fixed costs of investments required to maintain a unit as a capacity resource (APIR). When actual net revenues are compared to actual avoidable costs in this analysis, the actual avoidable costs are adjusted to exclude APIR. Existing APIR is a sunk cost and a rational decision about retirement would ignore such sunk costs. For example, APIR may reflect investments in environmental technology which were made in prior years to keep units in service. These costs are sunk costs.

The MMU calculated actual unit specific energy and ancillary service net revenues for a range of technology classes. These net revenues were compared to avoidable costs to determine the extent to which PJM energy and ancillary service markets alone provide sufficient incentive for continued operations in PJM markets. Energy and ancillary service revenues were then combined with the actual capacity revenues, and compared to actual avoidable costs to determine the extent to which the capacity market revenues covered any shortfall between energy and ancillary net revenues and avoidable costs. The comparison of the two results is an indicator of the significance of the role of the capacity market in maintaining the viability of existing generating units.

Actual energy net revenues include day-ahead and balancing market energy revenues, less short run marginal costs, plus any applicable day-ahead or balancing operating reserve credits. Ancillary service revenues include actual unit credits for regulation services, synchronized reserves, black start service, and reactive revenues.

The MMU calculated average avoidable costs in dollars per MW-year based on submitted avoidable cost rate (ACR) data for units associated with the most recent 2017/2018 RPM Auction.[31] For units that did not submit ACR data, the default ACR was used.

The PJM capacity market design provides supplemental signals to the market based on the locational and forward looking need for generation resources to maintain system reliability. For this analysis, unit specific capacity revenues associated with the 2017/2018 and 2018/2019 Delivery Years, reflecting commitments made in base residual auctions (BRA) and subsequent incremental auctions, net of any performance penalties, were added to unit specific energy and ancillary net revenues to determine total revenue from PJM markets in 2018. Any unit with a significant portion of installed capacity designated as FRR committed was excluded from the analysis.[32] For units exporting capacity, the applicable BRA clearing price was applied.

Net revenues were analyzed for most technologies for which avoidable costs are developed in the capacity market. The analysis is on a unit specific basis, using individual unit actual net revenues and individual unit avoidable costs. Net revenues are calculated using units' price-based offers for technologies other than nuclear. For nuclear units, public data on revenues and costs are used.

The unit specific energy and ancillary net revenues, avoidable costs and capacity revenues, on which the class averages shown in Table 7-33 are based, include a wide range of results. In order to illustrate this underlying variability while preserving confidentiality of unit specific information, the data are aggregated and summarized by quartile.

Table 7-33 shows energy and ancillary service net revenues by quartile for select technology classes.[33] Differences in energy net revenue within technology classes reflect differences in incremental costs which are a function of plant efficiencies, input fuels, variable operating and maintenance (VOM) expenses and emission rates, as well as differences in location which affect both the LMP and delivered costs for input fuels. Unlike the other technologies, nuclear data is from public sources in order to avoid revealing confidential information. Nuclear unit revenue is based on day-ahead LMP from the relevant node as shown in Table 7-36, adjusted by the class average equivalent availability factor. Nuclear unit capacity revenue assumes that the unit cleared its full installed capacity at the BRA locational clearing price as shown in Table 7-37.

Table 7-33 also includes new entrant energy market net revenue from Table 7-9, Table 7-11, Table 7-13, Table 7-15, and Table 7-17 for comparison purposes. The new entrant net revenues are higher than existing unit CC net revenues and coal plant net revenues, are not comparable to existing unit CT net revenues, are within the range of existing unit diesel net revenues, and are on the low end of existing nuclear plant net revenues.

31 If a unit submitted updated ACR data for an incremental auction, that data was used instead of the ACR data submitted for the base residual auction.

32 The MMU cannot assess the risk of FRR designated units because the incentives associated with continued operations for these units are not transparent and are not aligned with PJM market incentives. For the same reasons, units with significant FRR commitments are excluded from the analysis of units potentially facing significant capital expenditures associated with environmental controls.

33 The quartile numbers in the table are the dividing line between the quartiles. The first quartile result means that 25 percent of units have lower net revenues, the median result means that 50 percent of units have lower net revenues and the third quartile result means that 75 percent of units have lower net revenues.

Table 7-33 Net revenue by quartile for select technologies: 2018

Technology	Total Installed Capacity (ICAP)	($/MW-Yr) Energy and ancillary service net revenue: New entrant	First quartile	Median	Third quartile	Capacity revenue: First quartile	Median	Third quartile	Energy, ancillary, and capacity revenue: First quartile	Median	Third quartile
CC - Combined Cycle	32,620	$101,049	$183	$25,986	$70,404	$27,598	$54,879	$72,011	$59,910	$99,901	$126,493
CT - Aero Derivative	5,998	$60,553	$4,823	$8,510	$14,933	$52,122	$56,788	$77,458	$57,817	$72,370	$89,018
CT - Industrial Frame	21,639	-	($176)	$3,121	$9,026	$38,759	$55,734	$62,898	$37,206	$58,380	$71,248
Coal Fired	48,320	$57,678	$10,783	$23,689	$43,210	$44,330	$52,891	$64,965	$48,492	$80,955	$113,828
Diesel	242	$8,811	$0	$4,804	$15,934	$45,851	$55,199	$60,534	$53,307	$59,877	$75,316
Hydro	2,750	-	$108,381	$150,088	$172,256	$33,730	$51,103	$69,248	$168,280	$208,772	$223,148
Nuclear	33,233	$225,071	$231,022	$269,003	$297,212	$52,901	$63,510	$65,710	$294,531	$334,559	$350,113
Oil or Gas Steam	10,997	-	($2,734)	$0	$15,597	$45,752	$54,362	$63,049	$44,632	$61,111	$67,596
Pumped Storage	4,721	-	$34,960	$60,299	$60,299	$61,888	$62,605	$65,877	$98,425	$105,845	$123,079

Table 7-34 shows the percent of avoidable costs covered by net revenue from PJM energy and ancillary services markets by quartiles. In 2018, a substantial portion of units did not achieve full recovery of avoidable costs through energy markets alone. After including capacity revenues, net revenues from all markets cover avoidable costs for even the first quartile of most technology types, although this is not the case for every individual unit and it is not the case for coal units.

The analysis of nuclear plants includes publicly available data on energy market prices, capacity prices, and an estimate of annual avoidable costs and incremental capital expenditures from the Nuclear Energy Institute (NEI) based on NEI's average across all U.S. nuclear plants.[34] [35] The NEI annual avoidable costs used in the analysis are for 2017, the most recent data available.

Table 7-34 Avoidable cost recovery by quartile: 2018

Technology	Total Installed Capacity (ICAP)	Recovery of avoidable costs from energy and ancillary net revenue: First quartile	Median	Third quartile	Recovery of avoidable costs from all markets: First quartile	Median	Third quartile
CC - Combined Cycle	32,620	1%	195%	527%	449%	748%	948%
CT - Aero Derivative	5,998	41%	72%	127%	490%	614%	755%
CT - Industrial Frame	21,639	(2%)	28%	83%	342%	536%	654%
Coal Fired	48,320	17%	38%	65%	79%	124%	175%
Diesel	242	0%	42%	139%	464%	521%	656%
Hydro	2,750	349%	484%	555%	542%	673%	719%
Nuclear	33,233	87%	102%	107%	108%	123%	133%
Oil or Gas Steam	10,997	(10%)	0%	15%	104%	182%	227%
Pumped Storage	4,721	385%	664%	664%	1,084%	1,166%	1,356%

Table 7-35 shows the proportion of units recovering avoidable costs from energy and ancillary services markets and from all markets. In 2018, capacity revenues were sufficient to cover the shortfall between energy revenues and avoidable costs for the majority of units and technology types in PJM, with the exception of coal and nuclear units.[36] [37] [38]

34 Operating costs from: Nuclear Energy Institute (October, 2018). "Nuclear Costs in Context," <https://www.nei.org/CorporateSite/media/filefolder/resources/reports-and-briefs/nuclear-costs-context-201810.pdf>.
35 The NEI costs for Hope Creek and Salem were both treated as those associated with a two unit configuration because all three units are located in the same area.
36 Operating costs from: Nuclear Energy Institute (October, 2018). "Nuclear Costs in Context," <https://www.nei.org/CorporateSite/media/filefolder/resources/reports-and-briefs/nuclear-costs-context-201810.pdf>.
37 The NEI costs for Hope Creek and Salem were both treated as those associated with a two unit configuration because all three units are located in the same area.
38 Analysis excludes Catawba 1 which joined PJM with the integration of DEOK.

Table 7-35 Proportion of units recovering avoidable costs: 2011 through 2018

	Units with full recovery from energy and ancillary net revenue								Units with full recovery from all markets							
Technology	2011	2012	2013	2014	2015	2016	2017	2018	2011	2012	2013	2014	2015	2016	2017	2018
CC - Combined Cycle	55%	46%	50%	72%	59%	63%	57%	66%	85%	79%	79%	95%	88%	93%	89%	98%
CT - Aero Derivative	15%	6%	6%	53%	15%	8%	10%	30%	100%	96%	76%	98%	100%	99%	100%	99%
CT - Industrial Frame	26%	23%	17%	38%	13%	8%	3%	21%	99%	98%	83%	100%	100%	100%	100%	96%
Coal Fired	31%	17%	27%	78%	16%	15%	12%	11%	82%	36%	54%	83%	64%	40%	36%	63%
Diesel	48%	42%	37%	69%	56%	33%	32%	39%	100%	100%	77%	100%	100%	100%	100%	97%
Hydro	74%	61%	95%	97%	81%	79%	95%	94%	81%	77%	97%	98%	100%	100%	97%	98%
Nuclear	-	-	53%	95%	16%	5%	16%	53%	-	-	63%	100%	58%	16%	53%	84%
Oil or Gas Steam	8%	6%	11%	15%	3%	0%	0%	10%	92%	78%	86%	85%	91%	88%	81%	76%
Pumped Storage	100%	100%	95%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%

Nuclear Net Revenue Analysis

The analysis of nuclear plants includes annual avoidable costs and incremental capital expenditures from the Nuclear Energy Institute (NEI) based on NEI's calculations of average costs for all U.S. nuclear plants.[39] [40] The analysis includes the most recent operating cost data and incremental capital expenditure data published by NEI, for 2017. This is likely to result in conservatively high costs for the forward looking analysis. NEI average operating costs have decreased since their peak in 2012 (19.0 percent decrease from 2012 through 2017 for all plants including single and multiple unit plants). NEI average incremental capital expenditures have decreased since their peak in 2012 (40.8 percent decrease from 2012 through 2017 for all plants including single and multiple unit plants). NEI's incremental capital expenditures peaked in 2012 as a result of regulatory requirements following the 2011 accident at the Fukushima nuclear plant in Japan.

The results for nuclear plants are sensitive to small changes in PJM energy and capacity prices.[41] When gas prices are high and LMPs are high as a result, net revenues to nuclear plants increase. In 2014, the polar vortex resulted in a significant increase in net revenues to nuclear plants. When gas prices are low and LMPs are low as a result, net revenues to nuclear plants decrease. In 2016, PJM energy prices were at the lowest level since the introduction of competitive markets on April 1, 1999, and remained low in 2017. As a result, in 2016 and 2017, a significant proportion of nuclear plants did not cover annual avoidable costs.[42] In 2018, high gas prices and high LMPs resulted in a significant increase in net revenues for nuclear plants in PJM. Energy prices in 2018 were significantly higher than in 2017 and forward prices for 2019 are similar to 2018 prices. The result is that nuclear plant net revenues have continued to increase during 2018 and for the three year forward period. The results for nuclear plants are also sensitive to changes in costs and whether unit costs are less than or greater than the benchmark NEI data. The results for nuclear plants are also sensitive to forward prices and the extent to which the owners of the plants sell the output forward.

Table 7-36 includes the publicly available data on energy market prices, Table 7-37 shows capacity market prices and Table 7-38 shows nuclear cost data for the eighteen nuclear plants in PJM and Oyster Creek, which retired September 17, 2018.[43]

For nuclear plants, all calculations are based on publicly available data in order to avoid revealing confidential information. Nuclear unit revenue is based on day-ahead LMP at the relevant node. Nuclear unit capacity revenue assumes that the unit cleared its full unforced capacity at the BRA locational clearing price. Unforced capacity is determined using the annual class average EFORd rate.

39 Operating costs from: Nuclear Energy Institute (October, 2018). "Nuclear Costs in Context," <https://www.nei.org/CorporateSite/media/filefolder/resources/reports-and-briefs/nuclear-costs-context-201810.pdf>. Individual plants may vary from the average due to factors such as geographic location, local labor costs, the timing of refueling outages and other unit specific factors.

40 The NEI costs for Hope Creek were treated as that of a two unit configuration because the unit is located in the same area as Salem 1 & 2. The net surplus of Hope Creek is sensitive to the accuracy of this assumption.

41 A change in the capacity market price of $24 per MW-day translates into a change in market revenue of $1.00 per MWh for a nuclear power plant operating in every hour.

42 The IMM submitted testimony in New Jersey on the same issues of nuclear economics. *Establishing Nuclear Diversity Certificate Program*. Bill No. S-877 New Jersey Senate Environment and Energy Committee. (2018). *Revised Statement of Joseph Bowring*.

43 Installed capacity is from NEI <https://www.nei.org/resources/map-of-us-nuclear-plants>.

Table 7-36 Nuclear unit day ahead LMP: 2008 through 2018

	ICAP	Average DA LMP ($/MWh)										
	(MW)	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Beaver Valley	1,808	$49.46	$31.51	$35.59	$37.43	$30.34	$34.24	$41.86	$30.35	$27.07	$29.11	$36.35
Braidwood	2,337	$48.10	$27.76	$31.48	$32.02	$27.51	$30.26	$37.34	$25.97	$24.30	$24.99	$27.11
Byron	2,300	$47.61	$23.98	$28.49	$28.09	$24.25	$29.22	$35.05	$21.00	$17.94	$23.79	$26.96
Calvert Cliffs	1,708	$78.63	$41.05	$51.27	$46.53	$35.19	$40.27	$57.88	$40.30	$32.64	$31.57	$38.79
Cook	2,069	$52.26	$32.20	$36.52	$37.41	$30.09	$34.14	$40.49	$29.94	$26.93	$28.03	$31.44
Davis Besse	894	-	-	-	$39.68	$31.68	$36.10	$47.21	$31.94	$27.80	$28.85	$34.44
Dresden	1,797	$48.76	$28.27	$32.73	$33.07	$28.42	$31.82	$39.22	$27.45	$25.89	$26.35	$28.25
Hope Creek	1,172	$73.34	$39.43	$48.03	$45.52	$33.07	$37.43	$51.99	$32.41	$23.20	$26.78	$32.93
LaSalle	2,271	$47.96	$27.71	$31.53	$31.93	$27.56	$30.94	$37.88	$26.28	$23.95	$24.71	$27.19
Limerick	2,242	$73.49	$39.49	$48.23	$45.27	$33.09	$37.28	$51.71	$32.65	$23.37	$26.99	$33.08
North Anna	1,892	$75.14	$39.89	$50.59	$45.47	$33.87	$38.55	$53.37	$38.05	$30.50	$31.27	$38.44
Oyster Creek	608	$75.49	$40.43	$49.29	$46.74	$33.69	$38.62	$52.85	$33.10	$23.79	$27.52	$34.03
Peach Bottom	2,347	$73.09	$39.32	$47.70	$44.73	$32.81	$37.37	$51.52	$31.98	$23.07	$26.76	$32.63
Perry	1,240	-	-	$36.99	$38.76	$31.68	$36.69	$46.14	$32.77	$27.84	$29.91	$37.24
Quad Cities	1,819	$47.28	$24.81	$27.53	$26.79	$20.43	$25.94	$30.71	$19.47	$18.04	$23.09	$25.54
Salem	2,328	$73.41	$39.51	$48.02	$45.50	$33.06	$37.40	$51.96	$32.37	$23.18	$26.76	$32.90
Surry	1,676	$71.96	$39.02	$49.30	$45.01	$33.62	$37.98	$51.75	$37.91	$30.08	$31.08	$38.50
Susquehanna	2,520	$69.96	$38.24	$45.95	$44.78	$32.10	$36.76	$50.93	$32.47	$23.66	$27.14	$32.42
Three Mile Island	803	$72.46	$39.11	$46.72	$44.15	$32.43	$36.83	$50.47	$30.94	$22.96	$27.12	$31.76

Table 7-37 Nuclear unit capacity market data: 2008 through 2021[44]

	ICAP	BRA Capacity Price ($/MWh)													
	(MW)	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Beaver Valley	1,808	$3.36	$4.24	$5.86	$5.54	$2.27	$0.95	$3.48	$5.41	$3.73	$3.93	$6.04	$5.25	$3.57	$4.69
Braidwood	2,337	$3.36	$4.24	$5.86	$5.54	$2.27	$0.95	$3.48	$5.41	$3.73	$3.93	$7.25	$8.59	$8.03	$7.95
Byron	2,300	$3.36	$4.24	$5.86	$5.54	$2.27	$0.95	$3.48	$5.41	$3.73	$3.93	$7.25	$8.59	$8.03	$7.95
Calvert Cliffs	1,708	$8.22	$9.03	$8.15	$5.54	$5.07	$7.72	$7.11	$6.35	$5.69	$4.96	$6.04	$5.26	$3.80	$4.86
Cook	2,069	$3.36	$4.24	$5.86	$5.54	$2.27	$0.95	$3.48	$5.41	$3.73	$3.93	$6.04	$5.25	$3.57	$4.69
Davis Besse	894	NA	NA	NA	NA	$2.35	$1.02	$3.48	$10.71	$8.81	$4.87	$6.04	$5.25	$3.57	$5.45
Dresden	1,797	$3.36	$4.24	$5.86	$5.54	$2.27	$0.95	$3.48	$5.41	$3.73	$3.93	$7.25	$8.59	$8.03	$7.95
Hope Creek	1,172	$6.91	$6.94	$7.37	$5.54	$5.22	$8.28	$7.43	$6.35	$5.69	$4.96	$7.50	$6.77	$6.59	$7.23
LaSalle	2,271	$3.36	$4.24	$5.86	$5.54	$2.27	$0.95	$3.48	$5.41	$3.73	$3.93	$7.25	$8.59	$8.03	$7.95
Limerick	2,242	$6.91	$6.94	$7.37	$5.54	$5.22	$8.28	$7.43	$6.35	$5.69	$4.96	$7.50	$6.77	$6.59	$7.23
North Anna	1,892	$3.36	$4.24	$5.86	$5.54	$2.27	$0.95	$3.48	$5.41	$3.73	$3.93	$6.04	$5.25	$3.57	$4.69
Oyster Creek	608	$6.91	$6.94	$7.37	$5.54	$5.22	$8.28	$7.43	$6.35	$5.69	$4.96	$7.50	NA	NA	NA
Peach Bottom	2,347	$6.91	$6.94	$7.37	$5.54	$5.22	$8.28	$7.43	$6.35	$5.69	$4.96	$7.50	$6.77	$6.59	$7.23
Perry	1,240	NA	NA	NA	NA	$2.35	$1.02	$3.48	$10.71	$8.81	$4.87	$6.04	$5.25	$3.57	$5.45
Quad Cities	1,819	$3.36	$4.24	$5.86	$5.54	$2.27	$0.95	$3.48	$5.41	$3.73	$3.93	$7.25	$8.59	$8.03	$7.95
Salem	2,328	$6.91	$6.94	$7.37	$5.54	$5.22	$8.28	$7.43	$6.35	$5.69	$4.96	$7.50	$6.77	$6.59	$7.23
Surry	1,676	$3.36	$4.24	$5.86	$5.54	$2.27	$0.95	$3.48	$5.41	$3.73	$3.93	$6.04	$5.25	$3.57	$4.69
Susquehanna	2,520	$3.36	$6.32	$7.37	$5.54	$5.07	$7.72	$7.11	$6.35	$5.69	$4.96	$6.04	$5.25	$3.80	$4.86
Three Mile Island	803	$3.36	$6.32	$7.37	$5.54	$5.07	$7.72	$7.11	$6.35	$5.69	$4.96	$6.04	$5.25	$3.80	$4.86

44 Oyster Creek retired September 17, 2018. Exelon. "Oyster Creek Generating Station Retires from Service," (September 17, 2018) <http://www.exeloncorp.com/newsroom/oyster-creek-retires>.

Table 7-38 Nuclear unit costs: 2008 through 2018[45]

	ICAP	NEI Costs ($/MWh)										
	(MW)	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Beaver Valley	1,808	$26.73	$29.76	$31.34	$34.51	$36.06	$33.84	$33.84	$32.90	$31.63	$30.89	$30.89
Braidwood	2,337	$26.73	$29.76	$31.34	$34.51	$36.06	$33.84	$33.84	$32.90	$31.63	$30.89	$30.89
Byron	2,300	$26.73	$29.76	$31.34	$34.51	$36.06	$33.84	$33.84	$32.90	$31.63	$30.89	$30.89
Calvert Cliffs	1,708	$26.73	$29.76	$31.34	$34.51	$36.06	$33.84	$33.84	$32.90	$31.63	$30.89	$30.89
Cook	2,069	$26.73	$29.76	$31.34	$34.51	$36.06	$33.84	$33.84	$32.90	$31.63	$30.89	$30.89
Davis Besse	894	$35.31	$39.36	$41.23	$45.45	$47.41	$44.16	$44.32	$44.51	$41.39	$42.66	$42.66
Dresden	1,797	$26.73	$29.76	$31.34	$34.51	$36.06	$33.84	$33.84	$32.90	$31.63	$30.89	$30.89
Hope Creek	1,172	$26.73	$29.76	$31.34	$34.51	$36.06	$33.84	$33.84	$32.90	$31.63	$30.89	$30.89
LaSalle	2,271	$26.73	$29.76	$31.34	$34.51	$36.06	$33.84	$33.84	$32.90	$31.63	$30.89	$30.89
Limerick	2,242	$26.73	$29.76	$31.34	$34.51	$36.06	$33.84	$33.84	$32.90	$31.63	$30.89	$30.89
North Anna	1,892	$26.73	$29.76	$31.34	$34.51	$36.06	$33.84	$33.84	$32.90	$31.63	$30.89	$30.89
Oyster Creek	608	$35.31	$39.36	$41.23	$45.45	$47.41	$44.16	$44.32	$44.51	$41.39	$42.66	$42.66
Peach Bottom	2,347	$26.73	$29.76	$31.34	$34.51	$36.06	$33.84	$33.84	$32.90	$31.63	$30.89	$30.89
Perry	1,240	$35.31	$39.36	$41.23	$45.45	$47.41	$44.16	$44.32	$44.51	$41.39	$42.66	$42.66
Quad Cities	1,819	$26.73	$29.76	$31.34	$34.51	$36.06	$33.84	$33.84	$32.90	$31.63	$30.89	$30.89
Salem	2,328	$26.73	$29.76	$31.34	$34.51	$36.06	$33.84	$33.84	$32.90	$31.63	$30.89	$30.89
Surry	1,676	$26.73	$29.76	$31.34	$34.51	$36.06	$33.84	$33.84	$32.90	$31.63	$30.89	$30.89
Susquehanna	2,520	$26.73	$29.76	$31.34	$34.51	$36.06	$33.84	$33.84	$32.90	$31.63	$30.89	$30.89
Three Mile Island	803	$35.31	$39.36	$41.23	$45.45	$47.41	$44.16	$44.32	$44.51	$41.39	$42.66	$42.66

Table 7-39 shows the surplus or shortfall in $/MWh for the eighteen nuclear plants in PJM and Oyster Creek calculated using this data.[46] In Table 7-39, eight nuclear plants with a total capacity of 13,461 MW in addition to Oyster Creek did not recover all their fuel costs, operating costs, and capital expenditures in 2016 and 2017, and 15 nuclear plants with a total capacity of 27,947 MW did not recover all their fuel costs, operating costs, and capital expenditures in 2016. The surplus or shortfall assumes that the unit cleared its full unforced capacity at the BRA locational clearing price.[47] Unforced capacity is determined using the annual class average EFORd rate.

Some nuclear plants did not clear the capacity market primarily as a result of decisions by plant owners about how to offer the plants. Three Mile Island did not clear the 2018/2019 Auction[48] and Three Mile Island, Quad Cities, and a portion of Byron's capacity did not clear the 2019/2020 Auction.[49] Three Mile Island and Quad Cities did not clear the 2020/2021 Auction.[50] Three Mile Island, Dresden, and most of Byron did not clear the 2021/2022 Auction.[51] Beaver Valley, Davis Besse, and Perry did not clear the 2021/2022 Auction.[52]

45 Oyster Creek retired September 17, 2018. Exelon. "Oyster Creek Generating Station Retires from Service," (September 17, 2018) <http://www.exeloncorp.com/newsroom/oyster-creek-retires>.

46 Analysis excludes Catawba 1 which is pseudo tied to PJM.

47 Installed capacity is from NEI <https://www.nei.org/resources/map-of-us-nuclear-plants>.

48 Exelon. "Exelon Announces Outcome of 2019-2020 PJM Capacity Auction," (May 25, 2016) <http://www.exeloncorp.com/newsroom/pjm-auction-results-2016>.

49 Exelon. "Exelon Announces Outcome of 2019-2020 PJM Capacity Auction," (May 25, 2016) <http://www.exeloncorp.com/newsroom/pjm-auction-results-2016>.

50 Exelon, "Exelon Announces Outcome of 2020-2021 PJM Capacity Auction," (May 24, 2017) <http://www.exeloncorp.com/newsroom/pjm-auction-results-release-2017>.

51 Exelon, "Exelon Announces Outcome of 2021-2022 PJM Capacity Auction," (May 24, 2018) <http://www.exeloncorp.com/newsroom/exelon-announces-outcome-of-2021-2022-pjm-capacity-auction>.

52 PRNewswire. "FirstEnergy Solutions Comments on Results of PJM Capacity Auction," (May 24, 2018) <https://www.prnewswire.com/news-releases/firstenergy-solutions-comments-on-results-of-pjm-capacity-auction-300654549.html>

Table 7-39 Nuclear unit surplus (shortfall) based on public data: 2008 through 2018

	ICAP	Surplus (Shortfall) ($/MWh)										
	(MW)	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Beaver Valley	1,808	$26.1	$6.0	$10.1	$8.5	($3.4)	$1.4	$11.5	$2.9	($0.8)	$2.1	$11.5
Braidwood	2,337	$24.7	$2.2	$6.0	$3.0	($6.3)	($2.6)	$7.0	($1.5)	($3.6)	($2.0)	$3.5
Byron	2,300	$24.2	($1.5)	$3.0	($0.9)	($9.5)	($3.7)	$4.7	($6.5)	($10.0)	($3.2)	$3.3
Calvert Cliffs	1,708	$60.1	$20.3	$28.1	$17.6	$4.2	$14.1	$31.1	$13.7	$6.7	$5.6	$13.9
Cook	2,069	$28.9	$6.7	$11.0	$8.4	($3.7)	$1.3	$10.1	$2.4	($1.0)	$1.1	$6.6
Davis Besse	894	NA	NA	NA	NA	($13.4)	($7.0)	$6.4	($1.9)	($4.8)	($8.9)	($2.2)
Dresden	1,797	$25.4	$2.8	$7.2	$4.1	($5.4)	($1.1)	$8.9	($0.0)	($2.0)	($0.6)	$4.6
Hope Creek	1,172	$53.5	$16.6	$24.1	$16.5	$2.2	$11.9	$25.6	$5.9	($2.7)	$0.9	$9.5
LaSalle	2,271	$24.6	$2.2	$6.0	$3.0	($6.2)	($1.9)	$7.5	($1.2)	($3.9)	($2.3)	$3.6
Limerick	2,242	$53.7	$16.7	$24.3	$16.3	$2.3	$11.7	$25.3	$6.1	($2.6)	$1.1	$9.7
North Anna	1,892	$51.8	$14.4	$25.1	$16.5	$0.1	$5.7	$23.0	$10.6	$2.6	$4.3	$13.6
Oyster Creek	608	$47.1	$8.0	$15.4	$6.8	($8.5)	$2.7	$16.0	($5.1)	($11.9)	($10.2)	($1.1)
Peach Bottom	2,347	$53.3	$16.5	$23.7	$15.8	$2.0	$11.8	$25.1	$5.4	($2.9)	$0.8	$9.2
Perry	1,240	NA	NA	NA	NA	($13.4)	($6.4)	$5.3	($1.0)	($4.7)	($7.9)	$0.6
Quad Cities	1,819	$23.9	($0.7)	$2.0	($2.2)	($13.4)	($7.0)	$0.3	($8.0)	($9.9)	($3.9)	$1.9
Salem	2,328	$53.6	$16.7	$24.0	$16.5	$2.2	$11.8	$25.5	$5.8	($2.8)	$0.8	$9.5
Surry	1,676	$48.6	$13.5	$23.8	$16.0	($0.2)	$5.1	$21.4	$10.4	$2.2	$4.1	$13.6
Susquehanna	2,520	$46.6	$14.8	$22.0	$15.8	$1.1	$10.6	$24.2	$5.9	($2.3)	$1.2	$7.6
Three Mile Island	803	$40.5	$6.1	$12.9	$4.2	($9.9)	$0.4	$13.3	($7.2)	($12.7)	($10.6)	($4.9)

In order to evaluate the expected viability of nuclear plants, analysis was performed based on forward energy market prices for 2019, 2020 and 2021 and known capacity market prices for 2019, 2020 and 2021. The purpose of the forward analysis is to evaluate whether current forward prices are consistent with nuclear plants covering their annual avoidable costs over the next three years. While the forward capacity market prices are known, actual energy prices will vary from forward values.

Table 7-40 shows PJM energy prices (LMP), capacity prices (BRA), and annual fuel, operating and capital expenditures for the 2019 through 2021 period. The LMPs are based on forward prices with a basis adjustment for the specific plant locations.[53] Forward prices are as of January 2, 2019. The capacity prices are known based on PJM capacity auction results.

Table 7-40 Forward prices in PJM energy and capacity markets and annual costs[54]

	ICAP	Average Forward LMP ($/MWh)				BRA Capacity Price ($/MWh)			2017 NEI Costs ($/MWh)		
	(MW)	2019	2020	2021	2022	2019	2020	2021	Fuel	Operating	Capital
Beaver Valley	1,808	$34.32	$33.37	$31.58	$30.38	$5.25	$3.57	$4.69	$6.44	$18.46	$5.99
Braidwood	2,337	$27.29	$26.53	$25.13	$24.12	$8.59	$8.03	$7.95	$6.44	$18.46	$5.99
Byron	2,300	$27.27	$26.51	$25.11	$24.10	$8.59	$8.03	$7.95	$6.44	$18.46	$5.99
Calvert Cliffs	1,708	$34.61	$33.88	$32.07	$30.81	$5.26	$3.80	$4.86	$6.44	$18.46	$5.99
Cook	2,069	$30.93	$29.94	$28.36	$27.22	$5.25	$3.57	$4.69	$6.44	$18.46	$5.99
Davis Besse	894	$33.44	$32.39	$30.69	$29.47	$5.25	$3.57	$5.45	$6.42	$27.32	$8.92
Dresden	1,797	$28.33	$27.52	$26.07	$25.03	$8.59	$8.03	$7.95	$6.44	$18.46	$5.99
Hope Creek	1,172	$29.69	$29.27	$27.69	$26.60	$6.77	$6.59	$7.23	$6.44	$18.46	$5.99
LaSalle	2,271	$27.29	$26.53	$25.13	$24.12	$8.59	$8.03	$7.95	$6.44	$18.46	$5.99
Limerick	2,242	$29.77	$29.33	$27.74	$26.66	$6.77	$6.59	$7.23	$6.44	$18.46	$5.99
North Anna	1,892	$34.19	$33.46	$31.67	$30.43	$5.25	$3.57	$4.69	$6.44	$18.46	$5.99
Peach Bottom	2,347	$29.56	$29.13	$27.56	$26.48	$6.77	$6.59	$7.23	$6.44	$18.46	$5.99
Perry	1,240	$34.88	$34.02	$32.21	$30.95	$5.25	$3.57	$5.45	$6.42	$27.32	$8.92
Quad Cities	1,819	$25.86	$25.18	$23.84	$22.88	$8.59	$8.03	$7.95	$6.44	$18.46	$5.99
Salem	2,328	$29.67	$29.24	$27.66	$26.58	$6.77	$6.59	$7.23	$6.44	$18.46	$5.99
Surry	1,676	$34.03	$33.29	$31.52	$30.28	$5.25	$3.57	$4.69	$6.44	$18.46	$5.99
Susquehanna	2,520	$29.06	$28.66	$27.09	$26.05	$5.25	$3.80	$4.86	$6.44	$18.46	$5.99
Three Mile Island	803	$28.51	$28.12	$26.60	$25.56	$5.25	$3.80	$4.86	$6.42	$27.32	$8.92

53 Forward prices on January 2, 2019. Forward prices are reported for PJM trading hubs which are adjusted to reflect the historical differences between prices at the trading hub and prices at the relevant plant locations. The basis adjustment is based on 2018 data.

54 Oyster Creek retired September 17, 2018. Exelon. "Oyster Creek Generating Station Retires from Service," (September 17, 2018) <http://www.exeloncorp.com/newsroom/oyster-creek-retires>.

Table 7-41 show the surplus or shortfall that would be received net of avoidable costs and incremental capital expenditures by year, based on forward prices, for the 2018 through 2021 period, on a per MWh basis. The fuel and operating costs are the 2017 NEI fuel, operating, and capital costs. Table 7-42 shows the total dollar surplus or shortfall and adjusts energy revenues and operating costs using the annual class average capacity factor. Based on forward prices for energy and known forward prices for capacity, all but three nuclear plants would cover their annual avoidable costs on average over the next three years (2019 through 2021). The three plants are Davis Besse, Perry, and Three Mile Island. In May 2017, TMI requested deactivation in 2019. In March 2018, Davis Besse and Perry requested deactivation in 2021. All three plants are single unit sites which have higher operating costs per MWh than multiple unit plants. The three plants together are 2,937 MW.

Table 7-41 Nuclear unit forward annual surplus (shortfall) in $/MWh[55]

	Surplus (Shortfall) ($/MWh)		
	2019	2020	2021
Beaver Valley	$8.68	$6.05	$5.39
Braidwood	$4.99	$3.67	$2.19
Byron	$4.97	$3.65	$2.18
Calvert Cliffs	$8.97	$6.79	$6.03
Cook	$5.29	$2.61	$2.16
Davis Besse	($3.97)	($6.70)	($6.52)
Dresden	$6.03	$4.66	$3.14
Hope Creek	$5.57	$4.97	$4.03
LaSalle	$4.99	$3.67	$2.19
Limerick	$5.65	$5.03	$4.08
North Anna	$8.55	$6.14	$5.48
Peach Bottom	$5.44	$4.83	$3.90
Perry	($2.53)	($5.07)	($5.00)
Quad Cities	$3.56	$2.32	$0.90
Salem	$5.55	$4.95	$4.00
Surry	$8.39	$5.97	$5.32
Susquehanna	$3.41	$1.56	$1.06
Three Mile Island	($8.91)	($10.74)	($11.20)

Table 7-42 Nuclear unit forward annual surplus (shortfall) ($ in millions)[56]

	Surplus (Shortfall) ($ in millions)		
	2019	2020	2021
Beaver Valley	$134.3	$93.5	$84.7
Braidwood	$106.4	$80.3	$51.7
Byron	$104.3	$78.6	$50.6
Calvert Cliffs	$131.0	$99.0	$89.3
Cook	$95.8	$48.4	$41.9
Davis Besse	($26.9)	($47.8)	($45.6)
Dresden	$97.3	$76.4	$53.8
Hope Creek	$57.9	$52.0	$43.3
LaSalle	$103.5	$78.0	$50.2
Limerick	$112.2	$100.5	$83.8
North Anna	$138.6	$99.3	$90.0
Peach Bottom	$113.4	$101.5	$84.1
Perry	($22.6)	($49.6)	($47.8)
Quad Cities	$61.3	$42.2	$20.9
Salem	$114.6	$102.8	$85.5
Surry	$120.5	$85.6	$77.6
Susquehanna	$77.7	$37.4	$28.2
Three Mile Island	($56.9)	($69.6)	($72.3)

Units At Risk

The definition of units at risk of retirement is units that are not expected to recover their avoidable costs from the market.

Unit revenues are a combination of energy and ancillary service revenues and capacity market revenues. Units that fail to recover and are expected to continue to fail to recover avoidable costs from total market revenues, including capacity market revenues, are at risk of retirement particularly if the results are expected to continue.[57] Units that failed to clear the most recent capacity auction(s) are at increased risk of retirement if this result is outside the control of the plant owner and is expected to continue. The profile of coal and nuclear units that are not expected to cover their going forward costs over the next three years is shown in Table 7-43.[58] [59] These units are considered at risk of retirement.[60]

The analysis of coal units compares expected energy and capacity market revenues to ACR values and exclude APIR over the period 2019-2021. Bus level forward LMPs are based on forward prices with a basis adjustment for

55 Oyster Creek retired September 17, 2018. Exelon. "Oyster Creek Generating Station Retires from Service," (September 17, 2018) <http://www.exeloncorp.com/newsroom/oyster-creek-retires>.

56 Oyster Creek retired September 17, 2018. Exelon. "Oyster Creek Generating Station Retires from Service," (September 17, 2018) <http://www.exeloncorp.com/newsroom/oyster-creek-retires>.

57 FRR coal units, external coal units, and coal units that have either already started the deactivation process or requested deactivation review are excluded from the at risk analysis.

58 Avoidable costs for coal units are ACR values and exclude APIR.

59 For nuclear units, avoidable costs consist of fuel costs, operating costs, and capital expenditures.

60 Units expected to continue operations for reasons not directly related to market prices are not considered at risk of retirement.

the specific plant locations.[61] Forward prices are as of January 2, 2019.

The nuclear plants considered to be at risk of retirement are the plants in Table 7-42 showing a shortfall over the period 2019-2021.

Based on these criteria, a total of 14,954 MW of coal and nuclear capacity are at risk of retirement, in addition to the units that are currently planning to retire. The 14,954 MW considered to be at risk of retirement consist of 12,017 MW of coal and 2,937 MW of nuclear capacity.

Table 7-43 Profile of coal and nuclear units at risk of retirement

Technology	No. Units	ICAP (MW)	Avg. 2018 Run Hrs	Avg. Unit Age (Yrs)	Avg. Heat Rate (Btu/MWh)
Coal Fired	24	12,017	3,983	51	10,029
Nuclear	3	2,937	-	38	-
Total	27	14,954			

61 Forward prices on January 2, 2019. Forward prices are reported for PJM trading hubs which are adjusted to reflect the historical differences between prices at the trading hub and prices at the relevant plant locations. The basis adjustment is based on 2018 data.

Environmental and Renewable Energy Regulations

Environmental requirements and renewable energy mandates have a significant impact on PJM markets.

The investments required for environmental compliance have resulted in higher offers in the Capacity Market, and in making the investments in some cases when those offers clear, and in the retirement of units in some cases when those offers do not clear. Environmental requirements and initiatives at both the federal and state levels and state renewable energy mandates and associated incentives have resulted in the construction of substantial amounts of renewable capacity in the PJM footprint, especially wind and solar resources. Renewable energy credit (REC) markets created by state programs, and federal tax credits have significant impacts on PJM wholesale markets. But state renewables programs in PJM are not coordinated with one another, are generally not consistent with the PJM market design or PJM prices, have widely differing objectives, have widely differing implied prices of carbon and are not transparent on pricing and quantities. The effectiveness of state renewables programs would be enhanced if they were coordinated with one another and with PJM markets, and increased transparency.

Overview

Federal Environmental Regulation

- **EPA Mercury and Air Toxics Standards Rule.** The U.S. Environmental Protection Agency's (EPA) Mercury and Air Toxics Standards rule (MATS) applies the Clean Air Act (CAA) maximum achievable control technology (MACT) requirement to new or modified sources of emissions of mercury and arsenic, acid gas, nickel, selenium and cyanide.[1] All coal steam units in PJM are compliant with the state and federal emissions limits established by MATS.
- **Air Quality Standards (NO_x and SO_2 Emissions).** The CAA requires each state to attain and maintain compliance with fine particulate matter (PM) and ozone national ambient air quality standards (NAAQS). The CAA also requires that each state prohibit emissions that significantly interfere with the ability of another state to meet NAAQS.[2]
- **National Emission Standards for Reciprocating Internal Combustion Engines.** The national emissions standards uniformly apply to all RICE.[3] All RICE are allowed to operate during emergencies, including declared Energy Emergency Alert Level 2 or five percent voltage/frequency deviations.[4]
- **Greenhouse Gas Emissions Rule.** On August 3, 2015, the EPA issued a final rule for regulating CO_2 from certain existing power generation facilities titled Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units (the Clean Power Plan).[5] On February 9, 2016, the U.S. Supreme Court issued a stay of the rule that will prevent its taking effect until judicial review is completed.[6] On October 10, 2017, the EPA proposed to repeal the Clean Power Plan based a determination that the Plan exceeds the EPA's authority under Section 111 of the EPAs Act.[7]
- **Cooling Water Intakes.** An EPA rule implementing Section 316(b) of the Clean Water Act (CWA) requires that cooling water intake structures reflect the best technology available for minimizing adverse environmental impacts.[8]

State Environmental Regulation

- **Regional Greenhouse Gas Initiative (RGGI).** The Regional Greenhouse Gas Initiative (RGGI) is a CO_2 emissions cap and trade agreement among Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New York, Rhode Island, and Vermont that applies to power generation facilities. New Jersey is in the process of resuming

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

2 CAA § 110(a)(2)(D)(i)(I).

3 EPA, Memorandum, Peter Tsirigotis Guidance on Vacatur of RICE NESHAP and NSPS Provisions for Emergency Engines (April 15, 2016).

4 See 40 CFR §§ 60.4211(f)(2)(ii)–(iii), 60.4243(d)(2)(ii)–(iii), and 63.6640(f)(2)(ii)–(iii) (Declared Energy Emergency Alert Level 2 or 5 percent voltage/frequency deviations); 40 CFR §§ 60.4211(f)(1), 60.4243(d)(1), and 63.6640(f)(1) ("There is no time limit on the use of emergency stationary ICE in emergency situations."); 40 §§ CFR 60.4211(f)(3), 60.4243(d)(3), 63.6640(f)(3)–(4).

5 *Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units*, EPA-HQ-OAR-2013-0602, Final Rule mimeo (Aug. 3, 2015), also known as the "Clean Power Plan."

6 North Dakota v. EPA, et al., Order 15A793.

7 *See Repeal of Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units*, Proposed Rule, EPA Docket No. EPA-HQ-OAR-2017-0355, 82 Fed. Reg. 48035 (Oct. 16, 2017).

8 See EPA, *National Pollutant Discharge Elimination System—Final Regulations to Establish Requirements for Cooling Water Intake Structures at Existing Facilities and Amend Requirements at Phase I Facilities*, EPA-HQ-OW-2008-0667, 79 Fed. Reg. 48300 (Aug. 15, 2014).

participation.[9] Virginia is making preparations to join.[10] The auction price in the December 5, 2018, auction for the 2015/2018 compliance period was $5.33 per ton. The clearing price is equivalent to a price of $5.88 per metric tonne, the unit used in other carbon markets. The price increased by $0.83 per ton, 18.4 percent, from $4.50 per ton from September 9, 2018, to $5.33 per ton for December 5, 2018.

- **Carbon Price.** If the price of carbon were $50.00 per metric tonne, the short run marginal costs would increase by $25.04 per MWh for a new combustion turbine (CT) unit, $17.72 per MWh for a new combined cycle (CC) unit and $43.15 per MWh for a new coal plant (CP).

State Renewable Portfolio Standards

Many states in PJM have enacted legislation to require that a defined percentage of retail suppliers' load be served by renewable resources, for which definitions vary. These are typically known as renewable portfolio standards, or RPS. As of December 31, 2018, Delaware, Illinois, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, and Washington, DC had renewable portfolio standards. Virginia and Indiana had voluntary renewable portfolio standards. Kentucky and Tennessee did not have renewable portfolio standards.

Emissions Controls in PJM Markets

Environmental regulations affect decisions about emission control investments in existing units, investment in new units and decisions to retire units. As a result of environmental regulations and agreements to limit emissions, many PJM units burning fossil fuels have installed emission control technology. As of December 31, 2018, 93.6 percent of coal steam MW had some type of flue-gas desulfurization (FGD) technology to reduce SO_2 emissions, while 99.5 percent of coal steam MW had some type of particulate control, and 94.2 percent of fossil fuel fired capacity in PJM had NO_X emission control technology. All coal steam units in PJM are compliant with the state and federal emissions limits established by MATS.

Renewable Generation

Total wind and solar generation was 2.8 percent of total generation in PJM for 2018. Tier I generation was 4.5 percent of total generation in PJM and Tier II generation was 2.7 percent of total generation in PJM for 2018. Only Tier 1 generation is renewable.

Recommendations

- The MMU recommends that renewable energy credit markets based on state renewable portfolio standards be brought into PJM markets as they are an increasingly important component of the wholesale energy market. (Priority: Medium. First reported 2010. Status: Not adopted.)
- The MMU recommends that the Commission reconsider its disclaimer of jurisdiction over RECs markets because, given market changes since that decision, it is clear that RECs materially affect jurisdictional rates. (Priority: High. New recommendation. Status: Not adopted.)
- 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. (Priority: Medium. New recommendation. Status: Not adopted.)
- The MMU recommends that jurisdictions with a renewable portfolio standard make the price and quantity data on supply and demand more transparent. (Priority: Low. First reported Q2, 2018. Status: Not adopted.)

Conclusion

Environmental requirements and renewable energy mandates at both the federal and state levels have a significant impact on the cost of energy and capacity in PJM markets. Renewable energy credit (REC) markets are markets related to the production and purchase of wholesale power, but FERC has determined that RECs are not regulated under the Federal Power Act unless the REC is sold as part of a transaction that also includes a wholesale sale of electric energy in a

9 Executive Order 7; see *Regional Greenhouse Gas Initiative*, State of New Jersey Department of Environmental Protection <http://www.state.nj.us/dep/aqes/rggi.html>.

10 See Regulation for Emissions Trading, 9 VAC 5-140. The Virginia Air Pollution Control Board is developing the regulation and considering public comments.

bundled transaction.[11] 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.

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

RECs markets are, as an economic fact, integrated with PJM markets including energy and capacity markets, but are not formally recognized as part of PJM markets. It would be preferable to have a single, transparent market for RECs operated by the PJM RTO that would meet the standards and requirements of all states in the PJM footprint including those with no RPS. This would provide better information for market participants about supply and demand and prices and contribute to a more efficient and competitive market and to better price formation. This could also facilitate entry by qualifying renewable resources by reducing the risks associated with lack of transparent market data. The MMU recommends that PJM states consider the development of a multistate framework for REC markets, for potential agreement on carbon pricing, and for coordination with PJM wholesale markets.

REC markets are not consistently or adequately transparent. Data on REC prices, clearing quantities and markets are not publicly available for all PJM states. The provision of more complete data would facilitate competition to provide energy from renewable sources.

The economic logic of RPS programs and the associated REC and SREC prices is not always clear. The price of carbon implied by REC prices ranges from $4.67 per tonne in Washington, D.C. to $35.41 per tonne in Pennsylvania. The price of carbon implied by SREC prices ranges from $17.71 per tonne in Pennsylvania to $812.07 per tonne in Washington, D.C. The effective prices for carbon compare to the 2018 average RGGI clearing price of $4.86 per tonne and to the social cost of carbon which is estimated in the range of $40 per tonne.[12] The impact on the cost of generation from a new combined cycle unit of an $800 per tonne carbon price would be $283.56 per MWh. The impact of a $40 per tonne carbon price would be $14.18 per MWh. This wide range of implied carbon prices is not consistent with an efficient, competitive, least cost approach to the reduction of emissions.

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

PJM markets could also provide a flexible mechanism to limit carbon output, for example by incorporating a consistent carbon price in unit offers which would be reflected in PJM's economic dispatch. If there is a social decision to limit carbon output, a consistent carbon price would be the most efficient way to implement that decision. The states in PJM could agree, if they decided it was in their interests, with the appropriate information, on a carbon price and on how to allocate the revenues from a carbon price that would make all states better off. The MMU continues to recommend that PJM provide modeling information to the states adequate to inform such a decision making process. A carbon price would

11 See 139 FERC ¶ 61,061 at PP 18, 22 (2012) ("[W]e conclude that unbundled REC transactions fall outside of the Commission's jurisdiction under sections 201, 205 and 206 of the FPA. We further conclude that bundled REC transactions fall within the Commission's jurisdiction under sections 201, 205 and 206 of the FPA,… [A]lthough a transaction may not directly involve the transmission or sale of electric energy, the transaction could still fall under the Commission's jurisdiction because it is 'in connection with' or 'affects' jurisdictional rates or charges.").

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

also be an alternative to specific subsidies to individual nuclear power plants and to the current wide range of implied carbon prices embedded in RPS programs and instead provide a market signal to which any resource could respond. The imposition of specific and prescriptive environmental dispatch rules would, in contrast, pose a threat to economic dispatch and efficient markets and create very difficult market power monitoring and mitigation issues. The provision of subsidies to individual units creates a discriminatory regime that is not consistent with competition. The use of inconsistent implied carbon prices by state is also inconsistent with an efficient market and inconsistent with the least cost approach to meeting state environmental goals.

Federal Environmental Regulation

The U.S. Environmental Protection Agency (EPA) administers the Clean Air Act (CAA). The CAA regulates air emissions by providing for the establishment of acceptable levels of emissions of hazardous air pollutants. The EPA issues technology based standards for major sources and area sources of emissions.[13] [14] EPA regulation of air quality covers:[15]

- Control of Mercury and Other Hazardous Air Pollutants: Section 112 of the CAA requires the EPA to promulgate emissions control standards, known as the National Emission Standards for Hazardous Air Pollutants (NESHAP), from both new and existing area and major sources. On December 21, 2011, the U.S. Environmental Protection Agency (EPA) issued its Mercury and Air Toxics Standards rule (MATS), which applies the CAA maximum achievable control technology (MACT) requirement to new or modified sources of emissions of mercury and arsenic, acid gas, nickel, selenium and cyanide. This rule remains under challenge in the courts, but the industry has already taken measures to come into compliance.

- Air Quality Standards: Control of NO_X, SO_2 and O_3 Emissions Allowances: The CAA requires each state to attain and maintain compliance with fine particulate matter and ozone national ambient air quality standards (NAAQS). Under NAAQS, the EPA establishes emission standards for six air pollutants, including NO_X, SO_2, O_3 at ground level, PM, CO, and Pb, and approves state plans to implement these standards, known as State Implementation Plans (SIPs). In January, 2015, the EPA began implementation of the Cross-State Air Pollution Rule (CSAPR) to address the CAA's requirement that each state prohibit emissions that significantly interfere with the ability of another state to meet NAAQS. Implementation was delayed in the courts, but CSAPR is now fully effective. The CSAPR requires specific states in the eastern and central United States to reduce power plant emissions of SO_2 and NO_X that cross state lines and contribute to ozone and fine particle pollution in other states. The CSPAR requires reductions to levels consistent with the 1997 ozone and fine particle and 2006 fine particle NAAQS. The CSAPR covers 28 states, including all of the PJM states except Delaware, and also excluding the District of Columbia.

- Emission Standards for Reciprocating Internal Combustion Engines: On January 14, 2013, the EPA signed a final rule amending its rules regulating emissions from a wide variety of stationary reciprocating internal combustion engines (RICE). RICE include certain types of electrical generation facilities like diesel engines typically used for backup, emergency or supplemental power, including facilities located behind the meter. These rules include: National Emission Standard for Hazardous Air Pollutants (NESHAP) for Reciprocating Internal Combustion Engines (RICE); New Source Performance Standards (NSPS) of Performance for Stationary Spark Ignition Internal Combustion Engines; and Standards of Performance for Stationary Compression Ignition Internal Combustion Engines (collectively RICE Rules). The RICE Rules apply to emissions such as formaldehyde, acrolein, acetaldehyde, methanol, CO, NO_X, volatile organic compounds (VOCs) and PM. The regulatory regime for RICE is complicated, and the applicable requirements turn on whether the engine is an "area source" or "major source," and the starter mechanism for the engine (compression ignition or spark ignition).

13 42 U.S.C. § 7401 et seq. (2000).

14 The EPA defines a "major source" as a stationary source or group of stationary sources that emit or have the potential to emit 10 tons per year or more of a hazardous air pollutant or 25 tons per year or more of a combination of hazardous air pollutants. An "area source" is any stationary source that is not a major source.

15 For more details, see the *2018 State of the Market Report for PJM*, Volume II, Appendix I: "Environmental and Renewable Energy Regulations."

The EPA's actions have and will continue to affect the cost to build and operate generating units in PJM, which in turn affects wholesale energy prices and capacity prices.

The EPA also administers the Clean Water Act (CWA), which regulates water pollution. The EPA implements the CWA through a permitting process, which regulates discharges from point sources that impact water quality and temperature in navigable waterways. In 2014, the EPA implemented new regulations for cooling water intakes under section 316(b) of the CWA.

CSAPR

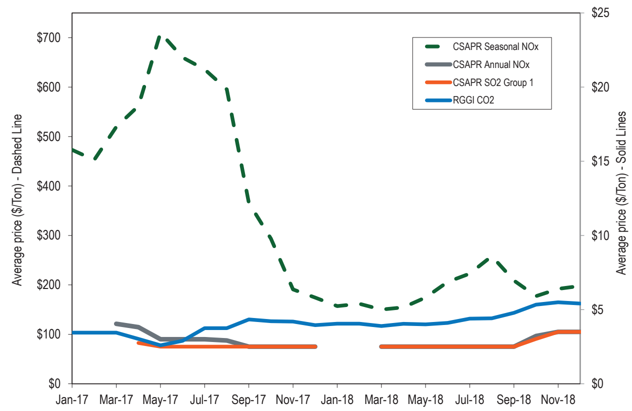
CSAPR is a federal emissions trading program designed to address the CAA's requirement that each state prohibit emissions that significantly interfere with the ability of another state to meet NAAQS. CSAPR emissions prices may be compared with RGGI emissions prices.

Section 126 of the CAA permits a downwind state to file a petition with the EPA to regulate the emissions from particular resources in another state. On October 5, 2018, EPA denied petitions filed under this provision filed by Delaware and Maryland.[16]

Figure 8-1 shows average, monthly settled prices for NO_X, CO_2 and SO_2 emissions allowances including CSAPR related allowances for January 1, 2017 through December 31, 2018. Figure 8-1 also shows the average, monthly settled price for the Regional Greenhouse Gas Initiative (RGGI) CO_2 allowances.

In 2018, CSAPR annual NO_X prices were 6.9 percent lower than in 2017. The CSAPR Seasonal NO_X price hit a peak of $710.12 in May 2017. The CSAPR Update resulted in fewer CSAPR Seasonal NO_X allowances.

Figure 8-1 Spot monthly average emission price comparison: 2017 through 2018



Federal Regulation of Greenhouse Gas Emissions

The EPA regulates CO_2 as a pollutant using CAA provisions that apply to pollutants not subject to NAAQS.[17 18]

The U.S. Court of Appeals for the Seventh Circuit has determined that a government agency can reasonably consider the global benefits of carbon emissions reduction against costs imposed in the U.S. by regulations in analyses known as the "Social Costs of Carbon."[19] The Court rejected claims raised by petitioners that raised concerns that the Social Cost of Carbon estimates were arbitrary, were not developed through transparent processes, and were based on inputs that were not peer-reviewed.[20] Although the decision applies only to the Department of Energy's regulations of manufacturers, it bolsters the ability of the EPA and state regulators to rely on social cost of carbon analyses.

On September 20, 2013, the EPA proposed national limits on the amount of CO_2 that new power plants would be

16 See *Response to Clean Air Act Section 126(b) Petitions From Delaware and Maryland*, EPA Docket No. EPA-HQ-OAR-2018-0295, 83 Fed. Reg. 50444 (Oct. 5, 2018). Delaware filed a petition requesting that the EPA regulate emissions from the Brunner Island coal plant in Pennsylvania, the Harrison coal plant in West Virginia, the Homer City coal plant in Pennsylvania and the Conemaugh coal plant in Pennsylvania. Maryland filed a petition requesting that the EPA regulate 36 generating units at coal plants located in Indiana, Kentucky, Ohio, Pennsylvania and West Virginia.

17 See CAA § 111.

18 On April 2, 2007, the U.S. Supreme Court overruled the EPA's determination that it was not authorized to regulate greenhouse gas emissions under the CAA and remanded the matter to the EPA to determine whether greenhouse gases endanger public health and welfare. Massachusetts v. EPA, 549 U.S. 497. On December 7, 2009, the EPA determined that greenhouse gases, including carbon dioxide, methane, nitrous oxide, hydrofluorocarbons, perfluorocarbons, and sulfur hexafluoride, endanger public health and welfare. See *Endangerment and Cause or Contribute Findings for Greenhouse Gases Under Section 202(a) of the Clean Air Act*, 74 Fed. Reg. 66496, 66497 (Dec. 15, 2009). In a decision dated June 26, 2012, the U.S. Court of Appeals for the D.C. Circuit upheld the endangerment finding, rejecting challenges brought by industry groups and a number of states. Coalition for Responsible Regulation, Inc., et al. v. EPA, No 09-1322.

19 See Zero Zone, Inc., et al., v. U.S. Dept. of Energy, et al., Case Nos. 14-2147, et al., Slip Op. (Aug. 8, 2016).

20 *Id.*

allowed to emit.[21] [22] The proposed rule includes two limits for fossil fuel fired utility boilers and integrated gasification combined cycle (IGCC) units based on the compliance period selected: 1,100 lb CO_2/MWh gross over a 12 operating month period, or 1,000–1,050 lb CO_2/MWh gross over an 84 operating month (seven year) period. The proposed rule also includes two standards for natural gas fired stationary combustion units based on the size: 1,000 lb CO_2/MWh gross for larger units (> 850 MMBtu/hr), or 1,100 lb CO_2/MWh gross for smaller units (≤ 850 MMBtu/hr).

On August 3, 2015, the EPA issued a final rule for regulating CO_2 from certain existing power generation facilities titled Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units (the Clean Power Plan).[23] The rule requires that individual state plans be submitted by September 6, 2016. However, on February 9, 2016, the U.S. Supreme Court issued a stay of the rule that will prevent its taking effect until judicial review is completed.[24]

On October 10, 2017, the EPA proposed to repeal the Clean Power Plan based on its determination that the Plan exceeds the EPA's authority under Section 111 of the EPA Act.[25] On August 8, 2017, the U.S. Court of Appeals for the District of Columbia Circuit issued an order continuing for 60 days to hold in abeyance court proceedings challenging the Clean Power Plan.[26]

On August 21, 2018, the EPA proposed to replace the Clean Power Plan with the Affordable Clean Energy (ACE) rule, which would establish emission guidelines for states to develop plans to address greenhouse gas emissions from existing coal-fired power plants.[27] The ACE (i) determines the "best system of emission reduction" (BSER) for existing power plants as on-site, heat-rate efficiency improvements; defines the "best system of emission reduction" (BSER) for existing power plants as on-site, heat-rate efficiency improvements; (ii) lists "candidate technologies" that states can use to establish standards of performance and incorporate into their plans; and (iii) revises the New Source Review (NSR) permitting program to promote improvements of existing power plants' efficiency.[28] The ACE would replace the Clean Power Plan's use of national greenhouse gas emissions limits with the application of emission reduction measures at the power plant. ACE would allow states to establish standards of performance based on a proposed list of candidate technologies to achieve the BSER standard. As a result, the impact on coal-fired generation would depend upon actions taken in their host state. ACE also proposes changes to New Source Review (NSR) regulations. NSR applies to new units or existing units receiving major modification. Under the revised NSR, only modifications that increase a plant's hourly rate of emissions would be deemed major and require an NSR analysis. Modifications that increased a plant's annual run time and annual emissions but not the hourly emissions rate would not require an NSR analysis.

Federal Regulation of Environmental Impacts on Water

The Clean Water Act (CWA) applies to the waters of the United States (WOTUS). The CWA defines WOTUS as "navigable waters."[29] On June 17, 2017, the EPA issued a rulemaking to rescind the definition of WOTUS proposed in the 2015 Clean Water Rule.[30] The rule would avoid the potential implementation of a broader definition of WOTUS included in the 2015 rule that was never implemented as the result of a stay issued by a reviewing Court.[31] The U.S. Supreme Court reversed the stay, but the EPA amended the 2015 Clean Water Rule to establish an applicability date of February 6, 2020.[32] The proposed rule would restore the pre 2015 rule to the code and the interpreting precedent applicable to the pre 2015 rule. As a result of the new applicability date, the pre 2015 rule is now in effect. The pre 2015

21 *Standards of Performance for Greenhouse Gas Emissions from New Stationary Sources: Electric Utility Generating Units*, Proposed Rule, EPA-HQ-OAR-2013-0495, 79 Fed. Reg. 1430 (January 8, 2014); The President's Climate Action Plan, Executive Office of the President (June 2013) (Climate Action Plan); Presidential Memorandum–Power Sector Carbon Pollution Standards, Environmental Protection Agency (June 25, 2013); Presidential Memorandum–Power Section Carbon Pollution Standards (June 25, 2013) ("June 25th Presidential Memorandum"). The Climate Action Plan can be accessed at: <http://www.whitehouse.gov/sites/default/files/image/president27sclimateactionplan.pdf>.

22 79 Fed. Reg. 1352 (Jan. 8, 2014).

23 *Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units*, EPA-HQ-OAR-2013-0602, Final Rule mimeo (Aug. 3, 2015), also known as the "Clean Power Plan."

24 North Dakota v. EPA, et al., Order 15A793.

25 See *Repeal of Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units*, Proposed Rule, EPA Docket No. EPA-HQ-OAR-2017-0355, 82 Fed. Reg. 48035 (Oct. 16, 2017).

26 See West Virginia v. EPA, No. 15-1363 (D.C. Cir.); North Dakota v. EPA, No. 15-1381 (D.C. Cir.).

27 See Emission Guidelines for Greenhouse Gas Emissions From Existing Electric Utility Generating Units; Revisions to Emission Guideline Implementing Regulations; Revisions to New Source Review Program, EPA Docket No. EPA–HQ–OAR–2017–0355, 83 Fed. Reg. 44746 (Aug. 31, 2018).

28 *Id.*

29 33 U.S.C. § 1362(7).

30 80 Fed. Reg. 37054 (June 29, 2015).

31 The stay was issued by the U.S. Court of Appeals for the Sixth Circuit on October 9, 2015.

32 See *Definition of "Waters of the United States"–Addition of an Applicability Date to 2015 Clean Water Rule*, Final Rule, EPA Docket No. EPA-HQ-OW-2017-0644, 83 Fed. Reg. 5200 (Feb. 6, 2018); National Assoc. of Mfg. v Dept. of Defense, No. 16-299 (S. Ct. Jan. 22, 2018).

rule includes all navigable waters and waters with a "significant nexus" to such waters.[33]

On December 11, 2018, the EPA and Department of the Army proposed a replacement definition of "waters of the United States."[34] The proposed definition would replace both the approaches used before and after the 2015 Rule. The proposed rule includes "waters within the ordinary meaning of the term, such as oceans, rivers, streams, lakes, ponds, and wetlands."[35] The proposed rule excludes "features that flow only in response to precipitation; groundwater, including groundwater drained through subsurface drainage systems; certain ditches; prior converted cropland; artificially irrigated areas that would revert to upland if artificial irrigation ceases; certain artificial lakes and ponds constructed in upland; water-filled depressions created in upland incidental to mining or construction activity; storm water control features excavated or constructed in upland to convey, treat, infiltrate, or store storm water run-off; wastewater recycling structures constructed in upland; and waste treatment systems."[36] The new rule would specifically exclude from EPA jurisdiction waters that are now included.

Water cooling systems at steam electric power generating stations are subject to regulation under the CWA. EPA regulations of discharges from steam electric power generating stations are set forth in the Generating Effluent Guidelines and Standards in 1974. These standards were amended most recently in 2015.

Section 301(a) of the CWA prohibits the point source discharge of pollutants to a water of the United States, unless authorized by permit. Section 402 of the CWA establishes the required permitting process, known as the National Pollutant Discharge Elimination System (NPDES). NPDES permits limit discharges and include monitoring and reporting requirements. NPDES permits last five years before they must be renewed.

NPDES permits must satisfy the more stringent of a technology based standard, known at Best Technology Available (BTA), or water quality standards. NDPES permits include limits designed to prevent discharges that would cause or contribute to violations of water quality standards. Water quality standards include thermal limits.

PJM states are authorized to issue NPDES permits, with the exception of the District of Columbia. Pennsylvania, Delaware, Indiana and Illinois are partially authorized; the balance of PJM states are fully authorized.

The CWA regulates intakes in addition to discharges.

Section 316(b) of the CWA requires that cooling water intake structures reflect the BTA for minimizing adverse environmental impacts. The EPA's rule implementing Section 316(b) requires an existing facility to use BTA to reduce impingement of aquatic organisms (pinned against intake structures) if the facility withdraws 25 percent or more of its cooling water from WOTUS and has a design intake flow of greater than two million gallons per day (mgd).[37]

Existing facilities withdrawing 125 mgd must conduct studies that may result in a requirement to install site-specific controls for reducing entrainment of aquatic organisms (drawn into intake structures). If a new generating unit is added to an existing facility, the rule requires addition of BTA that either (i) reduces actual intake flow at the new unit to a level at least commensurate with what can be attained using a closed-cycle recirculating system or (ii) reduces entrainment mortality of all stages of aquatic organisms that pass through a sieve with a maximum opening dimension of 0.56 inches to a prescribed level.

Federal Regulation of Coal Ash

The EPA administers the Resource Conservation and Recovery Act (RCRA), which governs the disposal of solid and hazardous waste.[38]

Solid waste is regulated under subtitle D, which encourages state management of nonhazardous industrial solid waste and sets nonbinding criteria for solid waste disposal facilities. Subtitle D prohibits open dumping. Subtitle D criteria are not directly enforced by the EPA. However, the owners of solid waste disposal

33 Rapanos v. U.S., 547 U.S. 715 (2006).

34 See *Revised Definition of "Waters of the United States,"* EPA Docket No. EPA-HQ-OW-2018-0149, 84 Fed. Reg. 4154 (Feb. 14, 2019).

35 *Id.* at 4155.

36 *Id.*

37 See EPA, *National Pollutant Discharge Elimination System—Final Regulations to Establish Requirements for Cooling Water Intake Structures at Existing Facilities and Amend Requirements at Phase I Facilities*, EPA-HQ-OW-2008-0667, 79 Fed. Reg. 48300 (Aug. 15, 2014).

38 42 U.S.C. §§ 6901 *et seq.*

facilities are exposed under the act to civil suits, and criteria set by the EPA under subtitle D can be expected to influence the outcome of such litigation.

Subtitle C governs the disposal of hazardous waste. Hazardous waste is subject to direct regulatory control by the EPA from the time it is generated until its ultimate disposal.

The EPA issued a rule under RCRA, the Coal Combustion Residuals rule (CCRR), which sets criteria for the disposal of coal combustion residues (CCRs), or coal ash, produced by electric utilities and independent power producers.[39] CCRs include fly ash (trapped by air filters), bottom ash (scooped out of boilers) and scrubber sludge (filtered using wet limestone scrubbers). These residues are typically stored on site in ponds (surface impoundments) or sent to landfills.

The CCRR exempts: (i) beneficially used CCRs that are encapsulated (i.e. physically bound into a product); (ii) coal mine filling; (iii) municipal landfills; (iv) landfills receiving CCRs before the effective date; (v) surface impoundments closed by the effective date; and (vi) landfills and surface impoundments on the site of generation facilities that deactivate prior to the effective date. Less restrictive criteria may also apply to some surface impoundments deemed inactive under not yet clarified criteria.

Table 8-1 describes the criteria and anticipated implementation dates.

Table 8-1 Minimum criteria for existing CCR ponds (surface impoundments) and landfills and date by which implementation is expected

Requirement	Description of requirement to be completed	Implementation Date
Location Restrictions (§ 257.60–§ 257.64)	For Ponds: Complete demonstration for placement above the uppermost aquifer, for wetlands, fault areas, seismic impact zones and unstable areas.	October 17, 2018
	For Landfills: Complete demonstration for unstable areas.	October 17, 2018
Design Criteria (§ 257.71)	For Ponds: Document whether CCR unit is either a lined or unlined CCR surface impoundment.	October 17, 2016
Structural Integrity (§ 257.73)	For Ponds: Install permanent marker.	December 17, 2015
	For Ponds: Compile a history of construction, complete initial hazard potential classification assessment, initial structural stability assessment, and initial safety factor assessment.	October 17, 2016
	Prepare emergency action plan.	April 17, 2017
Air Criteria (§ 257.80)	Ponds and Landfills: Prepare fugitive dust control plan.	October 17, 2015
Run-On and Run-Off Controls (§ 257.81)	For Landfills: Prepare initial run-on and run-off control system plan.	October 17, 2016
Hydrologic and Hydraulic Capacity (§ 257.82)	Prepare initial inflow design flood control system plan.	October 17, 2016
Inspections (§ 257.83)	For Ponds and Landfills: Initiate weekly inspections of the CCR unit.	October 17, 2015
	For Ponds: Initiate monthly monitoring of CCR unit instrumentation.	October 17, 2015
	For Ponds and Landfills: Complete the initial annual inspection of the CCR unit.	January 17, 2016
Groundwater Monitoring and Corrective Action (§ 257.90–§ 257.98)	For Ponds and Landfills: Install the groundwater monitoring system; develop the groundwater sampling and analysis program; initiate the detection monitoring program; and begin evaluating the groundwater monitoring data for statistically significant increases over background levels.	October 17, 2017
Closure and Post-Closure Care (§ 257.103–§ 257.104)	For Ponds and Landfills: Prepare written closure and post-closure care plans.	October 17, 2016
Recordkeeping, Notification, and Internet Requirements (§ 257.105–§ 257.107)	For Ponds and landfills: Conduct required recordkeeping; provide required notifications; establish CCR website.	October 17, 2015

39 *See Hazardous and Solid Waste Management System; Disposal of Coal Combustion Residuals From Electric Utilities*, 80 Fed. Reg. 21302 (April 17, 2015).

On March 1, 2018, the EPA proposed a rule amending the CCRR.[40] The proposal includes:

- A change to allow a state regulatory program to establish alternative risk-based groundwater protection standards for constituents that do not have an established maximum contaminant level (MCL), rather than the use of background levels that are currently required. The proposal also requests public comment on whether a facility may be allowed to establish alternative risk-based standards using a certified professional engineer or other means, subject to EPA oversight.
- A request for comment on whether the current deadlines for groundwater monitoring and analysis remain appropriate.
- A request for public comment on modifying the location restrictions and associated deadlines concerning construction or operation of a CCR landfill or surface impoundment in certain areas.
- Changes to allow states to establish alternative requirements for how facilities respond to and remediate releases from CCR landfills and surface impoundments. The proposal also requests comment on allowing states to determine when an unlined surface impoundment that is leaking may undertake corrective action rather than be forced to stop receiving CCR and close.
- The addition of boron to the list of constituents for which facilities would need to perform assessment monitoring.

Effective August 9, 2018, the EPA approved (i) revised groundwater protections standards for constituents without an established MCL, (ii) alternative performance standards and (iii) extended deadlines for placement of waste in CCR units closing for cause in certain situations.[41] The other identified issues remain pending.

40 EPA Press Release, EPA Proposes First of Two Rules to Amend Coal Ash Disposal Regulations, Saving Up To $100M Per Year in Compliance Costs <https://www.epa.gov/newsreleases/epa-proposes-first-two-rules-amend-coal-ash-disposal-regulations-saving-100m-year> (March 1, 2018).

41 See *Hazardous and Solid Waste Management System: Disposal of Coal Combustion Residuals From Electric Utilities; Amendments to the National Minimum Criteria (Phase One, Part One)*, EPA Docket No. EPA–HQ–OLEM–2017–0286, 83 Fed. Reg. 36435 (July 30, 2018).

State Environmental Regulation

States have in some cases enacted emissions regulations more stringent or potentially more stringent than federal requirements:[42]

- **New Jersey HEDD.** Units that run only during peak demand periods have relatively low annual emissions, and have less reason to make such investments under the EPA transport rules. New Jersey addressed the issue of NO_X emissions on peak energy demand days with a rule that defines peak energy usage days, referred to as high electric demand days or HEDD, and imposes operational restrictions and emissions control requirements on units responsible for significant NO_X emissions on such high energy demand days. New Jersey's HEDD rule, which became effective May 19, 2009, applies to HEDD units, which include units that have a NO_X emissions rate on HEDD equal to or exceeding 0.15 lbs/MMBtu and lack identified emission control technologies.
- **Illinois Air Quality Standards (NO_X, SO_2 and Hg).** The State of Illinois has promulgated its own standards for NO_X, SO_2 and Hg (mercury) known as Multi-Pollutant Standards (MPS) and Combined Pollutants Standards (CPS). MPS and CPS establish standards that are more stringent and take effect earlier than comparable Federal regulations, such as the EPA's MATS.

State Regulation of Greenhouse Gas Emissions

RGGI

The Regional Greenhouse Gas Initiative (RGGI) is a cooperative effort by Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New York, Rhode Island, and Vermont to cap CO_2 emissions from power generation facilities.[43] New Jersey is in the process of resuming participation. On January 29, 2018, New Jersey Governor Phil Murphy signed an executive order to take all steps necessary to rejoin the RGGI program but New Jersey is still not part of RGGI.[44] Virginia is

42 For more details, see the *2018 State of the Market Report for PJM*, Volume 2, Appendix I: "Environmental and Renewable Energy Regulations."

43 RGGI provides a link on its website to state statutes and regulations authorizing its activities, which can be accessed at: <http://www.rggi.org/design/regulations>.

44 Executive Order 7; see Regional Greenhouse Gas Initiative, State of New Jersey Department of Environmental Protection <http://www.state.nj.us/dep/aqes/rggi.html>.

considering joining RGGI. The Virginia Air Pollution Control Board is in the process of developing administrative rules that would facilitate its participation.[45]

RGGI generates revenues for the participating states which have spent approximately 64 percent of revenues on energy efficiency, 16 percent on clean and renewable energy, 4 percent on greenhouse gas abatements and 10 percent on direct bill assistance.[46]

Table 8-2 RGGI CO_2 allowance auction prices and quantities in short tons and metric tonnes: 2009/2011, 2012/2014 and 2015/2018 Compliance Periods[47]

	Short Tons			Metric Tonnes		
Auction Date	Clearing Price	Quantity Offered	Quantity Sold	Clearing Price	Quantity Offered	Quantity Sold
September 25, 2008	$3.07	12,565,387	12,565,387	$3.38	11,399,131	11,399,131
December 17, 2008	$3.38	31,505,898	31,505,898	$3.73	28,581,678	28,581,678
March 18, 2009	$3.51	31,513,765	31,513,765	$3.87	28,588,815	28,588,815
June 17, 2009	$3.23	30,887,620	30,887,620	$3.56	28,020,786	28,020,786
September 9, 2009	$2.19	28,408,945	28,408,945	$2.41	25,772,169	25,772,169
December 2, 2009	$2.05	28,591,698	28,591,698	$2.26	25,937,960	25,937,960
March 10, 2010	$2.07	40,612,408	40,612,408	$2.28	36,842,967	36,842,967
June 9, 2010	$1.88	40,685,585	40,685,585	$2.07	36,909,352	36,909,352
September 10, 2010	$1.86	45,595,968	34,407,000	$2.05	41,363,978	31,213,514
December 1, 2010	$1.86	43,173,648	24,755,000	$2.05	39,166,486	22,457,365
March 9, 2011	$1.89	41,995,813	41,995,813	$2.08	38,097,972	38,097,972
June 8, 2011	$1.89	42,034,184	12,537,000	$2.08	38,132,781	11,373,378
September 7, 2011	$1.89	42,189,685	7,847,000	$2.08	38,273,849	7,118,681
December 7, 2011	$1.89	42,983,482	27,293,000	$2.08	38,993,970	24,759,800
March 14, 2012	$1.93	34,843,858	21,559,000	$2.13	31,609,825	19,558,001
June 6, 2012	$1.93	36,426,008	20,941,000	$2.13	33,045,128	18,997,361
September 5, 2012	$1.93	37,949,558	24,589,000	$2.13	34,427,270	22,306,772
December 5, 2012	$1.93	37,563,083	19,774,000	$2.13	34,076,665	17,938,676
March 13, 2013	$2.80	37,835,405	37,835,405	$3.09	34,323,712	34,323,712
June 5, 2013	$3.21	38,782,076	38,782,076	$3.54	35,182,518	35,182,518
September 4, 2013	$2.67	38,409,043	38,409,043	$2.94	34,844,108	34,844,108
December 4, 2013	$3.00	38,329,378	38,329,378	$3.31	34,771,837	34,771,837
March 5, 2014	$4.00	23,491,350	23,491,350	$4.41	21,311,000	21,311,000
June 4, 2014	$5.02	18,062,384	18,062,384	$5.53	16,385,924	16,385,924
September 3, 2014	$4.88	17,998,687	17,998,687	$5.38	16,328,139	16,328,139
December 3, 2014	$5.21	18,198,685	18,198,685	$5.74	16,509,574	16,509,574
March 11, 2015	$5.41	15,272,670	15,272,670	$5.96	13,855,137	13,855,137
June 3, 2015	$5.50	15,507,571	15,507,571	$6.06	14,068,236	14,068,236
September 3, 2015	$6.02	25,374,294	25,374,294	$6.64	23,019,179	23,019,179
December 2, 2015	$7.50	15,374,274	15,374,274	$8.27	13,947,311	13,947,311
March 9, 2016	$5.25	14,838,732	14,838,732	$5.79	13,461,475	13,461,475
June 1, 2016	$4.53	15,089,652	15,089,652	$4.99	13,689,106	13,689,106
September 7, 2016	$4.54	14,911,315	14,911,315	$5.00	13,527,321	13,527,321
December 7, 2016	$3.55	14,791,315	14,791,315	$3.91	13,418,459	13,418,459
March 8, 2017	$3.00	14,371,300	14,371,300	$3.31	13,037,428	13,037,428
June 7, 2017	$2.53	14,597,470	14,597,470	$2.79	13,242,606	13,242,606
September 8, 2017	$4.35	14,371,585	14,371,585	$4.80	13,037,686	13,037,686
December 8, 2017	$3.80	14,687,989	14,687,989	$4.19	13,324,723	13,324,723
March 14, 2018	$3.79	13,553,767	13,553,767	$4.18	12,295,774	12,295,774
June 13, 2018	$4.02	13,771,025	13,771,025	$4.43	12,492,867	12,492,867
September 9, 2018	$4.50	13,590,107	13,590,107	$4.96	12,328,741	12,328,741
December 5, 2018	$5.33	13,360,649	13,360,649	$5.88	12,120,580	12,120,580

Table 8-2 shows the RGGI CO_2 auction clearing prices and quantities for the 2008/2011 compliance period auctions, the 2012/2014 compliance period auctions and 2015/2018 compliance period auctions held as of December 5, 2018, in short tons and metric tonnes.[48] Prices for auctions held December 5, 2018, were $5.33 per allowance (equal to one

45 Regulation for Emissions Trading, 9 VAC 5-140.

46 Investment of RGGI Proceeds Through 2015, The Regional Greenhouse Gas Initiative, <https://www.rggi.org/sites/default/files/Uploads/Proceeds/RGGI_Proceeds_Report_2015.pdf>.

47 See Regional Greenhouse Gas Initiative, "Auction Results," <http://www.rggi.org/market/co2_auctions/results> (Accessed Jan. 24, 2019).

48 The September 3, 2015, auction included additional Cost Containment Reserves (CCRs) since the clearing price for allowances was above the CCR trigger price of $6.00 per ton in 2015. The auctions on March 5, 2014, and September 3, 2015, were the only auctions to use CRRs.

ton of CO_2), above the current price floor of $2.21 for RGGI auctions.[49] The RGGI base budget for CO_2 will be reduced by 2.5 percent per year each year from 2015 through 2020. The price increased from the last auction clearing price of $4.50 in September 2018.

State Renewable Portfolio Standards

Nine PJM jurisdictions have enacted legislation that requires that a defined percentage of retail load be served by renewable resources, for which there are many standards and definitions. These requirements are known as renewable portfolio standards, or RPS. In PJM jurisdictions that have adopted an RPS, load serving entities are often required by law to meet defined shares of load using specific renewable and/or alternative energy sources commonly called "eligible technologies." Load serving entities may generally fulfill these obligations in one of two ways: they may use their own generation resources classified as eligible technologies to produce power or they may purchase renewable energy credits (RECs) that represent a known quantity of power produced with eligible technologies by other market participants or in other geographical locations. Load serving entities that fail to meet the percent goals set in their jurisdiction's RPS are penalized with alternative compliance payments.

Renewable energy sources replenish naturally in a short period of time but are flow limited and include solar, geothermal, wind, biomass and hydropower from flowing water. Renewable energy sources are virtually inexhaustible in duration but limited in the amount of energy that is available per unit of time. Nonrenewable energy sources do not replenish in a short period of time and include crude oil, natural gas, coal and uranium (nuclear energy).[50] Some state portfolios allow nonrenewable energy sources as part of their Renewable Portfolio Standard.

As of December 31, 2018, Delaware, Illinois, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, and Washington, D.C. had renewable portfolio standards that are mandatory and include penalties in the form of alternative compliance payments for underperformance.

Two PJM jurisdictions have enacted voluntary renewable portfolio standards. Load serving entities in states with voluntary standards are not bound by law to participate and face no alternative compliance payments. Instead, incentives are offered to load serving entities to develop renewable generation or, to a more limited extent, purchase RECs. As of December 31, 2018, Virginia and Indiana had renewable portfolio standards that are voluntary and do not include penalties in the form of alternative compliance payments for underperformance.

In this section, voluntary standards will not be directly compared to RPS with enforceable compliance payments. Indiana's voluntary standard illustrates the issue. Although a voluntary standard including target shares was enacted by the Indiana legislature in 2011, no load serving entities have volunteered to participate in the program.[51]

Three PJM states have no renewable portfolio standards. Kentucky and Tennessee have enacted no renewable portfolio standards. West Virginia had a voluntary standard, but it was repealed.[52]

How each state satisfies its renewable portfolio standard requirements should be more transparent. While some jurisdictions publish transparent information regarding total REC generation, how the standard is fulfilled and the total cost to the state, some jurisdictions do not readily publish this information. Some states provide adequate information with respect to the total cost for the RPS, where the RECs originated that fulfill the RPS requirements and if the state fulfilled the RPS goals. Pennsylvania and Maryland both provide enough information and serve as a model for other states. The MMU recommends that jurisdictions with a renewable portfolio standard make the compliance data available in a more complete and transparent manner.

Since a REC may be applied in years other than the year in which it was generated, each vintage of RECs for each state has a different price. For example, the Pennsylvania Alternative Energy Portfolio Standard allows an electric distribution company or generation supplier to retain RECs from the current reporting year

49 RGGI measures carbon in short tons (short ton equals 2,000 pounds) while world carbon markets measure carbon in metric tonnes (metric tonne equals 1,000 kilograms or 2,204.6 pounds).

50 Renewable Energy Explained, U.S. Energy Information Administration, <https://www.eia.gov/energyexplained/index.php?page=renewable_home>, (Accessed March 1, 2019).

51 See the Indiana Utility Regulatory Commission's "2018 Annual Report," at 36 (Oct. 2018) <https://www.in.gov/iurc/files/IURC%20AR%202018%20WEB3.pdf>.

52 See Enr. Com. Sub. For H. B. No. 2001.

for use toward satisfying their REC obligation in either of the two subsequent reporting years.[53]

Table 8-3 shows the percent of retail electric load that must be served by renewable and/or alternative energy resources under each PJM jurisdictions' RPS by year. Recent updates to RPS include legislation enacted on May 24, 2018, in New Jersey that raised New Jersey's RPS requirement to 21 percent by 2020, 35 percent by 2025, and 50 percent by 2030. The New Jersey statute requires generators to source increasing amounts of electricity from behind the meter solar, 4.3 percent by 2019, 4.9 percent by 2020, and 5.1 percent by 2021. The legislation also included provisions promoting the development of solar power in the state.[54] The Board of Public Utilities is directed to develop and provide an orderly transition to a new or modified program to support distributed solar. The Board must also design a Community Solar Energy Pilot Program that would "permit customers of an electric public utility to participate in a solar energy project that is remotely located from their properties but is within their electric public utility service territory to allow for a credit to the customer's utility bill equal to the electricity generated that is attributed to the customer's participation in the solar energy project." The pilot program would convert into a permanent program within three years. The statute targets the development of 600 MW of electric storage by 2021 and 2,000 MW by 2030.

In October 2016, the Council of the District of Columbia passed legislation that expanded the District's RPS program and increased the percent of retail load in the District that must be served by renewable energy resources to 50 percent by 2032.[55] On December 15, 2016, the Michigan State Senate approved Senate Bill 438 (S.B. 438) which increased the Michigan RPS percent requirements. The previous version of the bill required that 10 percent of retail electric load in Michigan be served by renewable and alternative energy resources in 2015 and subsequent years. S.B. 438 increased the percent of retail electric load to be served by renewable and alternative energy resources in Michigan to be 12.5 percent in 2019 and 2020 and 15 percent in 2021 and subsequent years.[56] In February 2017, the Maryland State House approved House Bill 1106 which increased the total RPS requirement from 20 percent by 2022 to 25 percent by 2020. In 2016, Maryland legislation established a pilot program for community solar energy systems.[57] Regulations for a three year pilot program developed by the Maryland Public Service Commission became effective July 18, 2016.

New Jersey and Maryland have taken significant steps to promote offshore wind. Both states enacted legislation for offshore wind renewable energy credits (ORECs) in 2010.[58]

On May 24, 2018, New Jersey enacted a statute directing the Board of Public Utilities to create an OREC program targeting installation of at least 3,500 MW of generation from qualified offshore wind projects by 2030 (plus 2,000 MW of energy storage capacity).[59] The New Jersey statute also reinstates certain tax incentives for offshore wind manufacturing activities. Governor Murphy has issue Executive Order No. 8, which call for full implementation of the statute. The BPU has initiated a proceeding considering the opening of an application window for qualified offshore wind projects.[60]

In 2017, the Maryland Public Service Commission announced two awards of ORECs to two commercial wind projects, Deepwater Wind's 120-MW Skipjack Wind Farm and U.S. Wind's 248-MW project. These project awards are the first under Maryland's 2010 OREC program.

53 Pennsylvania General Assembly, "Alternative Energy Portfolio Standards Act – Enactment Act of Nov. 30, 2004, P.L. 1672, No. 213", Section (e)(6).

54 N.J. S. 2314/A. 3723.

55 See Council of the District of Columbia. B21-0650—Renewable Portfolio Standard Expansion Amendment Act of 2016. <http://lims.dccouncil.us/Legislation/B21-0650> (Accessed April 26, 2018).

56 See Michigan Legislature. Senate Bill 0438 (2015) <http://legislature.mi.gov/doc.aspx?2015-SB-0438> (Accessed April 26, 2018).

57 Md. S.B. 1087.

58 See Offshore Wind Economic Development Act of 2010, P.L. 2010, c. 57, as amended, N.J.S.A. 48:3-87 to -87.2.

59 N.J. S. 2314/A. 3723.

60 BPU Docket No. QO18080851.

Table 8-3 Renewable standards of PJM jurisdictions: 2018 to 2030[61]

Jurisdiction with RPS	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Delaware	17.50%	19.00%	20.00%	21.00%	22.00%	23.00%	24.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%
Illinois	13.00%	14.50%	16.00%	17.50%	19.00%	20.50%	22.00%	23.50%	25.00%	25.00%	25.00%	25.00%	25.00%
Maryland	18.30%	20.40%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%
Michigan	10.00%	12.50%	12.50%	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%
New Jersey	19.13%	21.58%	28.60%	28.60%	28.60%	28.40%	28.30%	42.00%	41.85%	41.24%	40.57%	39.71%	54.08%
North Carolina	10.00%	10.00%	10.00%	12.50%	12.50%	12.50%	12.50%	12.50%	12.50%	12.50%	12.50%	12.50%	12.50%
Ohio	4.50%	5.50%	6.50%	7.50%	8.50%	9.50%	10.50%	11.50%	12.50%	12.50%	12.50%	12.50%	12.50%
Pennsylvania	14.70%	15.20%	15.70%	18.00%	18.00%	18.00%	18.00%	18.00%	18.00%	18.00%	18.00%	18.00%	18.00%
Washington, D.C.	16.50%	18.00%	20.00%	20.00%	20.00%	20.00%	23.00%	26.00%	29.00%	32.00%	35.00%	38.00%	42.00%
Jurisdiction with Voluntary Standard													
Indiana	4.00%	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%
Virginia	7.00%	7.00%	7.00%	7.00%	12.00%	12.00%	12.00%	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%
Jurisdiction with No Standard													
Kentucky	No Renewable Portfolio Standard												
Tennessee	No Renewable Portfolio Standard												
West Virginia	No Renewable Portfolio Standard												

Each PJM jurisdiction with an RPS identifies the type of generation resources that may be used for compliance. These resources are often called eligible technologies. Some PJM jurisdictions with RPS group different eligible technologies into tiers based on the magnitude of their environmental impact. Of the nine PJM states with mandatory RPS, Maryland, New Jersey, Pennsylvania, and Washington, DC group the eligible technologies that must be used to comply with their RPS programs into Tier I and Tier II resources. Though there are minor differences across these four jurisdictions' definitions of Tier I resources, technologies that use solar photovoltaic, solar thermal, wind, ocean, tidal, biomass, low-impact hydro, and geothermal sources to produce electricity are classified as Tier I resources. Table 8-4 shows the tier I standards for PJM states.[62] All eligible technologies for the RPS standards in Table 8-4 satisfy the EIA definition of renewable energy.[63]

Table 8-4 Tier I renewable standards of PJM jurisdictions: 2018 to 2030

Jurisdiction with RPS	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Maryland	15.80%	20.40%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%	25.00%
New Jersey	12.33%	14.18%	21.00%	21.00%	21.00%	21.00%	21.00%	35.00%	35.00%	35.00%	35.00%	35.00%	50.00%
Pennsylvania	6.50%	7.00%	7.50%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%
Washington, D.C.	15.50%	17.50%	20.00%	20.00%	20.00%	20.00%	23.00%	26.00%	29.00%	32.00%	35.00%	38.00%	42.00%

Delaware, Illinois, Michigan, North Carolina, and Ohio do not classify the resources eligible for their RPS standards by tiers. In Delaware, Illinois, North Carolina, and Ohio, eligible technologies are largely but not completely renewable resources. Michigan is the only state with an RPS that does not classify eligible technologies into tiers and also includes nonrenewable technologies. Michigan's RPS includes coal gasification, industrial cogeneration, and coal with carbon capture and storage as eligible technologies.

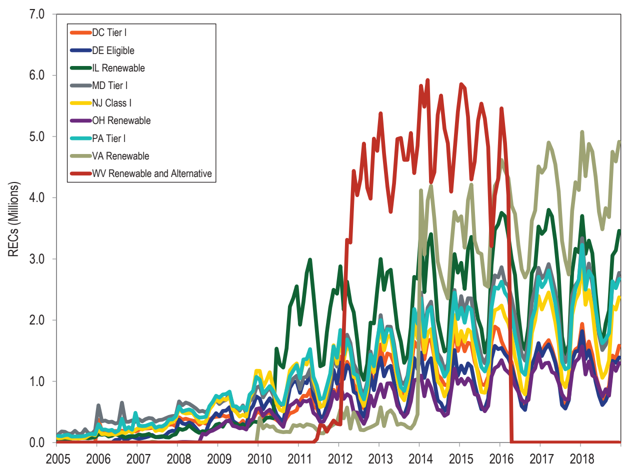
RECs do not need to be used during the year in which they are generated. The result is that there may be multiple prices for a REC based on the year in which it was generated. RECs typically have a shelf life of five years during which they can be used to satisfy a state's RPS requirement. For example if a load serving entity (LSE) owns renewable generation and the renewable generation exceeds the LSE's RECs purchase obligation for the current year, the LSE can either sell the REC to another LSE or hold the REC for use in a subsequent year.

Figure 8-2 shows the number of RECs eligible monthly by state for January 1, 2005, through December 31, 2018.[64] The figure includes Tier I or the equivalent REC type available in each state. Washington DC, Maryland, and Pennsylvania classify these RECs as Tier I, New Jersey classifies the RECs as Class I and Delaware, Illinois, Ohio, Virginia and

61 This shows the total standard of renewable resources in all PJM jurisdictions, including Tier I, Tier II and Tier III resources.
62 This includes New Jersey's Class I renewable standard.
63 Renewable Energy Explained, U.S. Energy Information Administration,<https://www.eia.gov/energyexplained/index.php?page=renewable_home>, (Accessed March 1, 2019).
64 Tier I REC volume obtained through PJM Environmental Information Services <https://www.pjm-eis.com/reports-and-events/public-reports.aspx> (Accessed March 1, 2019).

Wester Virginia classify these RECs as renewable or eligible. West Virginia repealed its renewable portfolio standard, and Virginia has a voluntary renewable portfolio standard.

Figure 8-2 Number of RECs eligible monthly by state: 2005 through 2018



The REC prices are the average price for each vintage of REC, defined by the year in which the associated power was generated, regardless of when the REC is consumed. REC prices are required to be publicly disclosed in Maryland, Pennsylvania and the District of Columbia, but in the other states REC prices are not publicly available.

Figure 8-3 shows the average Tier I REC price by jurisdiction from January 1, 2009, through December 31, 2018. Tier I REC prices are lower than SREC prices.

Figure 8-3 Average Tier I REC price by jurisdiction: 2009 through 2018

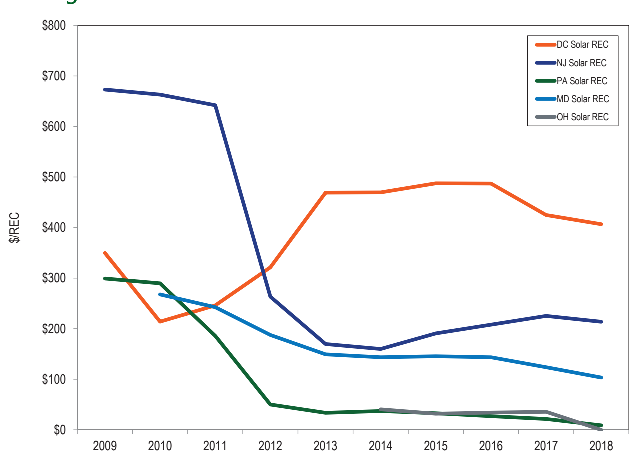


Table 8-5 shows the percent of retail electric load that must be served by Tier II or a specific type of resource under each PJM jurisdiction's RPS by year. Tier II resources are generally not renewable resources. Table 8-5 also shows specific technology requirements that PJM jurisdictions have added to their renewable portfolio standards. The standards shown in Table 8-5 are included in the total RPS requirements presented in Table 8-3. Illinois requires that a defined proportion of retail load be served by wind and solar resources, increasing from 9.75 percent of load served in 2018 to 18.75 percent in 2026. Maryland, New Jersey, Pennsylvania and Washington, DC all have Tier II or "Class 2" standards, which allow specific nonrenewable technology types, such as waste coal units located in Pennsylvania, to qualify for renewable energy credits. By 2021, North Carolina's RPS requires that 0.2 percent of power be generated using swine waste and that 900 GWh of power be produced by poultry waste. Maryland established a minimum standard for offshore wind in 2017 that takes effect in 2021 with a requirement that 1.37 percent of load be served by offshore wind. The standard increases to 2.03 percent in 2023.[65]

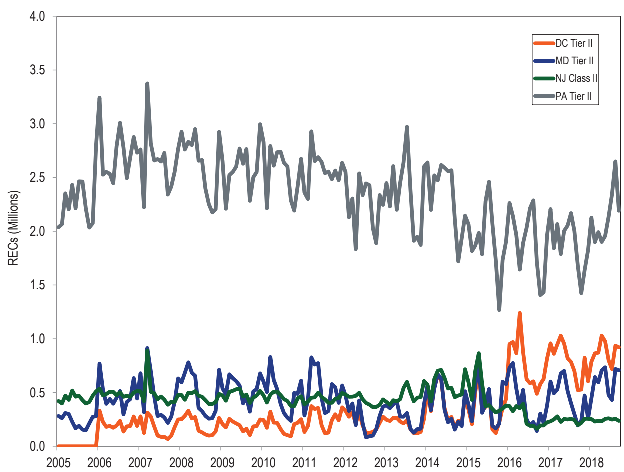
65 Order No. 88192, Public Service Commission of Maryland, Table 2, p. 81, (May 11, 2017), <https://www.psc.state.md.us/wp-content/uploads/Order-No.-88192-Case-No.-9431-Offshore-Wind.pdf>.

Table 8-5 Additional renewable standards of PJM jurisdictions: 2018 to 2030

Jurisdiction	Type of Standard	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Illinois	Wind and Solar	9.75%	10.88%	12.00%	13.13%	14.25%	15.38%	16.50%	17.63%	18.75%	18.75%	18.75%	18.75%	18.75%
Illinois	Distributed Generation	0.13%	0.15%	0.16%	0.18%	0.19%	0.21%	0.22%	0.24%	0.25%	0.25%	0.25%	0.25%	0.25%
Maryland	Tier II Standard	2.50%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Maryland	Off Shore Wind				1.37%	1.36%	2.03%	2.01%	2.01%	1.99%	1.98%	1.96%	1.96%	1.94%
New Jersey	Class II Standard	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%
North Carolina	Swine Waste	0.14%	0.14%	0.14%	0.20%	0.20%	0.20%	0.20%	0.20%	0.20%	0.20%	0.20%	0.20%	0.20%
North Carolina	Poultry Waste (in GWh)	900	900	900	900	900	900	900	900	900	900	900	900	900
Pennsylvania	Tier II Standard	8.20%	8.20%	8.20%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%
Washington, D.C.	Tier II Standard	1.00%	0.50%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%

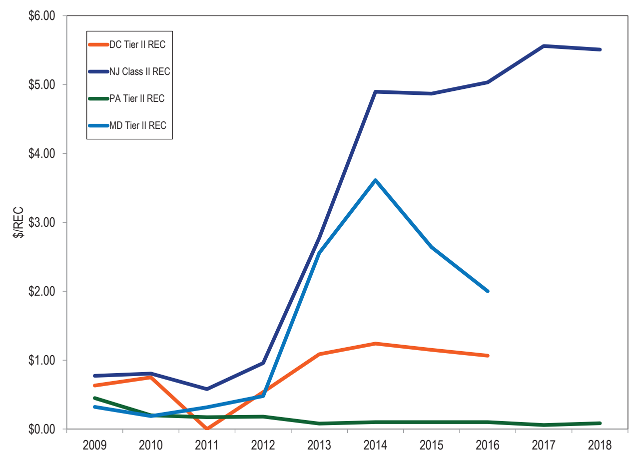
Figure 8-4 shows the number of Tier II RECs eligible monthly by state for January 1, 2005, through December 31, 2018.[66] The figure includes Tier II or the equivalent REC type available in each state. Washington DC, Maryland, and Pennsylvania classify these RECs as Tier II and New Jersey classifies the RECs as Class II.

Figure 8-4 Number of Tier II RECs eligible monthly by state: 2005 through 2018



Tier II prices are lower than SREC and Tier I REC prices. Figure 8-5 shows the average Tier II REC price by jurisdiction for January 1, 2009 through December 31, 2018. Pennsylvania had the lowest average Tier II REC prices at $0.08 per REC while New Jersey had the highest average Tier II REC prices at $5.51 per REC.[67]

Figure 8-5 Average Tier II REC price by jurisdiction: 2009 through 2018[68]



Some PJM jurisdictions have specific solar resource RPS requirements. These solar requirements are included in the total requirements shown in Table 8-3 but must be met by solar RECs (SRECs) only. Table 8-6 shows the percent of retail electric load that must be served by solar energy resources under each PJM jurisdiction's RPS by year. Delaware, Illinois, Maryland, New Jersey, North Carolina, Ohio, Pennsylvania, and Washington, DC have requirements for the proportion of load to be served by solar. Pennsylvania and Delaware allow only solar photovoltaic resources to fulfill their solar requirements. Solar thermal units like solar hot water heaters that do not generate electricity are considered Tier II. Indiana, Kentucky, Michigan, Tennessee, Virginia, and West Virginia have no specific solar standards. The New Jersey legislature in May 2018 increased the solar standard from 3.2 percent to 4.3 percent for 2018. The new solar standard is 5.1 percent for energy years 2020

66 Tier II REC volume obtained through PJM Environmental Information Services <https://www.pjm-eis.com/reports-and-events/public-reports.aspx> (Accessed March 1, 2019).

67 Tier II REC price information obtained through Evomarkets <http://www.evomarkets.com> (Accessed Jan. 24, 2019). There were not any reported cleared purchases for January 1, through Dec. 31, 2018, for DC Tier II REC or MD Tier II RECs.

68 Tier II REC price information obtained through Evomarkets <http://www.evomarkets.com> (Accessed Jan. 24, 2019). There were not any reported cleared purchases for January 1, 2017 through December 31, 2018 for DC Tier II REC or MD Tier II RECs.

through 2022 and the standard gradually decreases to 1.1 percent for 2032.[69]

Table 8-6 Solar renewable standards by percent of electric load for PJM jurisdictions: 2018 to 2030

Jurisdiction with RPS	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Delaware	1.75%	2.00%	2.25%	2.50%	2.75%	3.00%	3.25%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%
Illinois	0.78%	0.87%	0.96%	1.05%	1.14%	1.23%	1.32%	1.41%	1.50%	1.50%	1.50%	1.50%	1.50%
Maryland	1.50%	1.95%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%
Michigan	No Minimum Solar Requirement												
New Jersey	4.30%	4.90%	5.10%	5.10%	5.10%	4.90%	4.80%	4.50%	4.35%	3.74%	3.07%	2.21%	1.58%
North Carolina	0.20%	0.20%	0.20%	0.20%	0.20%	0.20%	0.20%	0.20%	0.20%	0.20%	0.20%	0.20%	0.20%
Ohio	0.18%	0.22%	0.26%	0.30%	0.34%	0.38%	0.42%	0.46%	0.50%	0.50%	0.50%	0.50%	0.50%
Pennsylvania	0.34%	0.39%	0.44%	0.50%	0.50%	0.50%	0.50%	0.50%	0.50%	0.50%	0.50%	0.50%	0.50%
Washington, D.C.	1.15%	1.35%	1.58%	1.85%	2.18%	2.50%	2.60%	2.85%	3.15%	3.45%	3.75%	4.10%	4.50%
Jurisdiction with Voluntary Standard													
Indiana	No Minimum Solar Requirement												
Virginia	No Minimum Solar Requirement												
Jurisdiction with No Standard													
Kentucky	No Renewable Portfolio Standard												
Tennessee	No Renewable Portfolio Standard												
West Virginia	No Renewable Portfolio Standard												

Figure 8-6 shows the number of SRECs eligible monthly by state for January 1, 2005, through December 31, 2018.[70]

Figure 8-6 Number of SRECs eligible monthly by state: 2005 through 2018

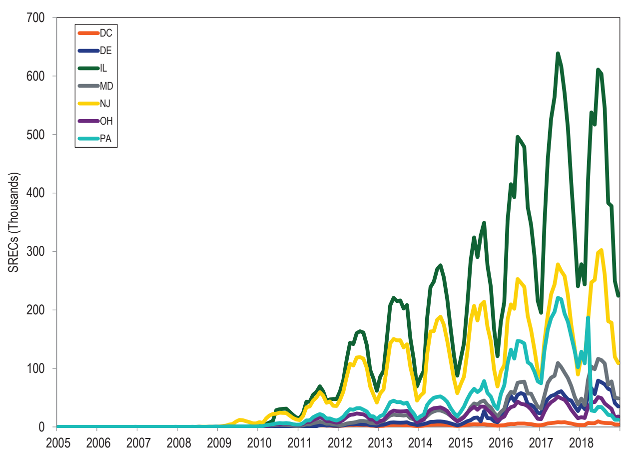


Figure 8-7 shows the average solar REC (SREC) price by jurisdiction for January 1, 2009, through December 31, 2018. The average NJ SREC prices dropped from $673 per SREC in 2009 to $214 per SREC in 2018. The limited supply of solar facilities in Washington, DC compared to the RPS requirement resulted in higher SREC prices. The average Washington, D.C. SREC price increased from $197 per SREC in 2011 to $407 per SREC in 2018.[71]

Figure 8-7 Average SREC price by jurisdiction: 2009 through 2018

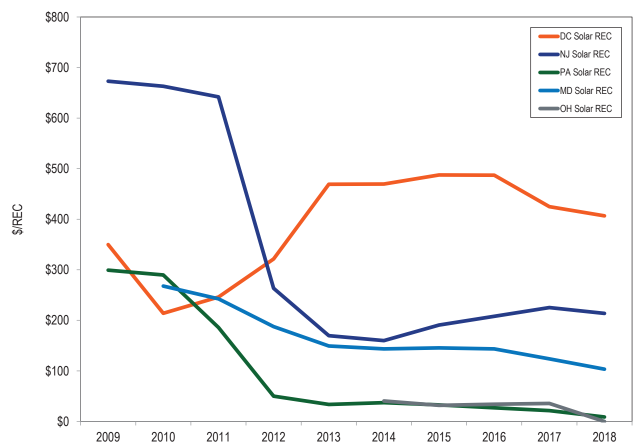


Figure 8-8 and Figure 8-9 show the percent of retail electric load that must be served by Tier I resources and Tier 2 resources in each PJM jurisdiction with a mandatory RPS. Figure 8-8 shows the percent of retail load that must be met with Tier I resources only. Because states that do not group eligible technologies into tiers generally classify eligible technologies in their RPS that are identical to Tier I resources, they are included in Figure 8-8. Figure 8-9 shows the percent of retail

69 "Assembly, No. 3723", State of New Jersey, 218th Legislature, (March 22, 2018), <http://www.njleg.state.nj.us/2018/Bills/A4000/3723_I1.PDF>.

70 SREC volume obtained through PJM Environmental Information Services <https://www.pjm-eis.com/reports-and-events/public-reports.aspx> (Accessed March 1, 2019).

71 Solar REC average price information obtained through Evomarkets, <http://www.evomarkets.com> (Accessed Jan. 24, 2019).

load that must be met with all eligible technologies, including Tier I, Tier II and alternative energy resources in all PJM jurisdictions with RPS. States with higher percent requirements for renewable and alternative energy resources are shaded darker. Jurisdictions with no standards or with only voluntary renewable standards are shaded gray. Pennsylvania's RPS illustrates the need to differentiate between percent requirements for Tier I and Tier II resources separately. Like all other PJM states with mandatory RPS, the Pennsylvania RPS identifies solar photovoltaic, solar thermal, wind, geothermal, biomass, and low-impact hydropower as Tier I resources. The Pennsylvania RPS identifies waste coal, demand side management, large-scale hydropower, integrated gasification combined cycle, clean coal and municipal solid waste as eligible Tier II resources. As a result, the 14.7 percent number in Figure 8-9 overstates the percent of retail electric load in Pennsylvania that must be served by renewable energy resources. The 6.5 percent number in Figure 8-8 is a more accurate measure of the percent of retail electric load in Pennsylvania that must be served by renewable energy resources.

Figure 8-8 Map of retail electric load shares under RPS – Tier I resources only: 2018

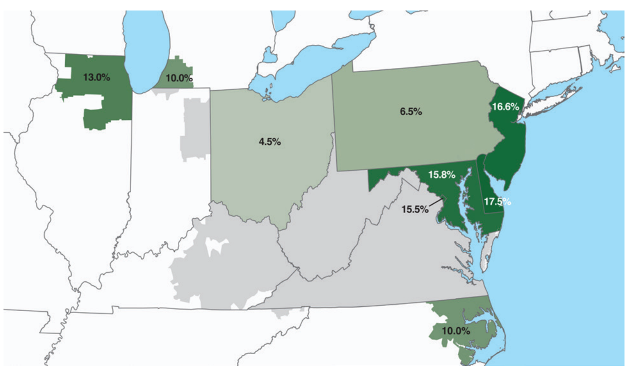
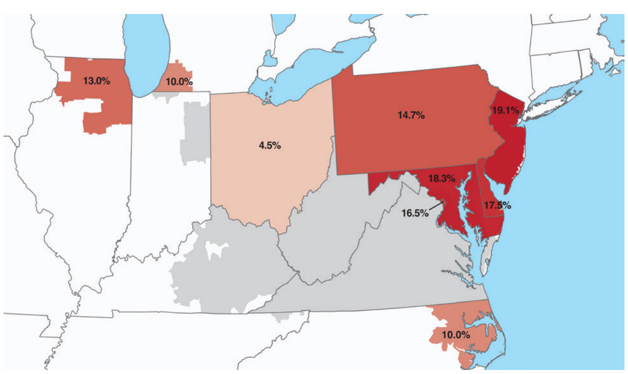


Figure 8-9 Map of retail electric load shares under RPS – Tier I and Tier II resources: 2018



Under the existing state renewable portfolio standards, approximately 9.4 percent of PJM load must be served by Tier I and Tier II renewable and alternative energy resources in 2018 and, if the proportion of load among states remains constant, 16.3 percent of PJM load must be served by renewable and alternative energy resources in 2028 under defined RPS rules. Approximately 7.4 percent of PJM load must be served by Tier I renewables in 2018 and, if the proportion of load among states remains constant, 14.1 percent of PJM load must be served by Tier I renewables in 2028 under defined RPS rules.

In jurisdictions with an RPS, load serving entities must either generate power from eligible technologies identified in each jurisdiction's RPS or purchase RECs from resources classified as eligible technologies. Table 8-7 shows generation by jurisdiction and resource type for 2018. Wind output was 21,542.1 GWh of 37,612.4 Tier I GWh, or 57.3 percent, in the PJM footprint. As shown in Table 8-7, 60,177.8 GWh were generated by Tier I and Tier II resources, of which Tier I resources were 62.5 percent. Total wind and solar generation was 2.9 percent of total generation in PJM for 2018. Tier I generation was 4.5 percent of total generation in PJM and Tier II was 2.7 percent of total generation in PJM for 2018. Landfill gas, solid waste and waste coal were 17,882.0 GWh, or 29.7 percent of the total Tier I and Tier II.

Table 8-7 Tier I and Tier II generation by jurisdiction and renewable resource type (GWh): 2018

	Tier I					Tier II				
Jurisdiction	Landfill Gas	Run-of-River Hydro	Solar	Wind	Total Tier I Credit	Pumped-Storage Hydro	Solid Waste	Waste Coal	Total Tier II Credit	Total Credit GWh
Delaware	34.3	0.0	0.0	0.0	34.3	0.0	0.0	0.0	0.0	34.3
Illinois	110.8	0.0	14.0	8,602.4	8,727.2	0.0	0.0	0.0	0.0	8,727.2
Indiana	19.4	49.2	13.4	4,795.7	4,877.8	0.0	0.0	0.0	0.0	4,877.8
Kentucky	0.0	314.5	0.0	0.0	314.5	0.0	0.0	0.0	0.0	314.5
Maryland	68.0	0.0	391.6	740.8	1,200.3	0.0	669.1	0.0	669.1	1,869.4
Michigan	25.6	65.9	7.4	0.0	98.8	0.0	0.0	0.0	0.0	98.8
New Jersey	275.9	35.7	606.7	12.6	930.8	313.6	1,396.7	0.0	1,710.3	2,641.1
North Carolina	0.0	869.9	568.0	542.6	1,980.5	0.0	0.0	0.0	0.0	1,980.5
Ohio	371.6	669.2	1.3	1,674.4	2,716.6	0.0	0.0	0.0	0.0	2,716.6
Pennsylvania	770.5	6,958.5	22.5	3,569.9	11,321.4	2,108.8	1,289.0	7,356.1	10,753.9	22,075.3
Tennessee	0.0	1,185.3	0.0	0.0	1,185.3	0.0	0.0	0.0	0.0	1,185.3
Virginia	600.9	594.2	469.7	0.0	1,664.8	4,583.9	875.9	2,958.1	8,417.9	10,082.7
Washington, D.C.	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
West Virginia	45.9	910.6	0.0	1,603.7	2,560.1	0.0	0.0	1,014.3	1,014.3	3,574.4
Total	2,322.8	11,652.9	2,094.5	21,542.1	37,612.4	7,006.3	4,230.7	11,328.4	22,565.5	60,177.8
Percent of Renewable Generation	3.9%	19.4%	3.5%	35.8%	62.5%	11.6%	7.0%	18.8%	37.5%	100.0%
Percent of Total Generation	0.3%	1.4%	0.3%	2.6%	4.5%	0.8%	0.5%	1.4%	2.7%	7.2%

Figure 8-10 shows the average hourly output by fuel type for January 1 through December 31 of 2014 through 2018. Tier I includes landfill gas, run-of-river hydro, solar and wind resources, as defined by the relevant states. Tier II includes pumped storage, solid waste and waste coal resources, as defined by the relevant states. Other includes biomass, miscellaneous, heavy oil, light oil, coal gas, propane, diesel, distributed generation, other biogas, kerosene and batteries.[72]

Figure 8-10 Average hourly output by fuel type: 2014 through 2018

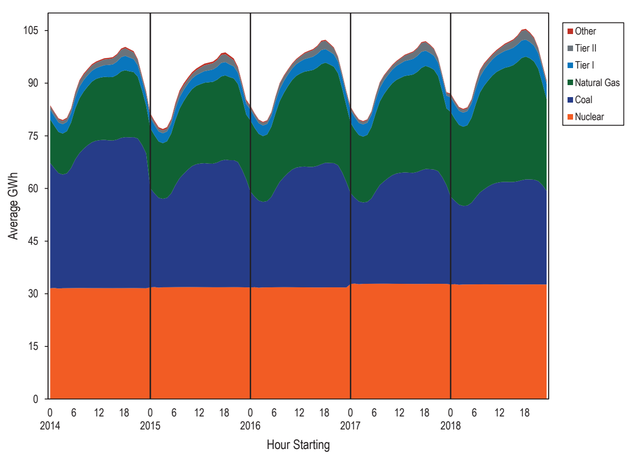


Table 8-8 shows the capacity of Tier I and Tier II resources in PJM by jurisdiction, as defined by primary fuel type. This capacity includes coal and natural gas units that qualify because they have a renewable fuel as an alternative fuel. For example, a coal generator that can also burn waste coal to generate power could list the alternative fuel as waste coal. A REC is only generated when using the fuel listed as Tier I or Tier II. New Jersey has the largest amount of solar capacity in PJM, 543.3 MW, or 31.5 percent of the total solar capacity. New Jersey's SREC prices were the highest in PJM at $673 per REC in 2009, and at $214 per REC in 2018. Wind resources are located primarily in western PJM, in Illinois and Indiana, which include 4,974.2 MW, or 61.1 percent of the total wind capacity.

72 *2018 State of the Market Report for PJM*, Volume 2, Section 3: Energy Market, Table 3-9.

Table 8-8 PJM renewable capacity by jurisdiction (MW): December 31, 2018

Jurisdiction	Coal	Landfill Gas	Natural Gas	Oil	Pumped-Storage Hydro	Run-of-River Hydro	Solar	Solid Waste	Waste Coal	Wind	Total
Delaware	0.0	8.1	1,797.0	13.0	0.0	0.0	0.0	0.0	0.0	0.0	1,818.1
Illinois	0.0	45.8	360.0	0.0	0.0	0.0	9.0	0.0	0.0	3,337.2	3,752.0
Indiana	0.0	8.0	0.0	0.0	0.0	8.2	10.1	0.0	0.0	2,022.5	2,048.8
Kentucky	0.0	0.0	0.0	0.0	0.0	166.0	0.0	0.0	0.0	0.0	166.0
Maryland	0.0	24.3	0.0	69.0	0.0	494.4	204.3	128.2	0.0	190.0	1,110.2
Michigan	0.0	8.0	0.0	0.0	0.0	13.9	4.6	0.0	0.0	0.0	26.5
Missouri	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	146.0	146.0
New Jersey	0.0	77.7	0.0	0.0	453.0	11.0	543.3	162.0	0.0	4.5	1,251.4
North Carolina	0.0	0.0	0.0	0.0	0.0	465.0	450.7	0.0	0.0	208.0	1,123.7
Ohio	9,910.0	68.2	0.0	156.0	0.0	119.1	1.1	0.0	0.0	669.8	10,924.2
Pennsylvania	0.0	201.8	2,346.0	0.0	1,269.0	893.3	19.5	261.8	1,611.0	1,367.2	7,969.6
Tennessee	0.0	0.0	0.0	0.0	0.0	156.6	0.0	0.0	0.0	0.0	156.6
Virginia	0.0	134.1	0.0	17.0	5,347.5	169.2	479.2	123.0	585.0	0.0	6,855.0
West Virginia	0.0	5.4	0.0	0.0	0.0	257.9	0.0	0.0	165.0	686.3	1,114.6
PJM Total	9,910.0	581.3	4,503.0	255.0	7,069.5	2,754.5	1,721.8	675.0	2,361.0	8,631.4	38,462.5

Table 8-9 shows renewable capacity registered in the PJM generation attribute tracking system (GATS). For example, roof top solar panels within the PJM footprint generate SRECs but are not PJM units. This includes solar capacity of 5,029.2 MW of which 2,048.2 MW is in New Jersey. These resources can earn renewable energy credits, and can be used to fulfill the renewable portfolio standards in PJM jurisdictions. There are 2,020 MW of capacity located in jurisdictions outside PJM that may qualify for specific renewable energy credits in some PJM jurisdictions. For example, there are 141.5 MW of capacity registered with GATS located in Alabama.

Table 8-9 Renewable capacity by jurisdiction, non-PJM units registered in GATS (MW): on December 31, 2018[73]

Jurisdiction	Coal	Hydroelectric	Landfill Gas	Natural Gas	Other Gas	Other Source	Solar	Solid Waste	Wind	Total
Alabama	0.0	0.0	0.0	0.0	0.0	0.0	0.0	141.5	0.0	141.5
Arkansas	0.0	0.0	0.0	0.0	18.0	0.0	0.0	0.0	0.0	18.0
Delaware	0.0	0.0	2.2	0.0	0.0	0.0	109.2	0.0	2.1	113.5
Georgia	0.0	0.0	0.0	0.0	0.0	0.0	152.2	258.9	0.0	411.1
Illinois	0.0	21.4	97.3	0.0	5.5	0.0	76.6	0.0	300.3	501.2
Indiana	0.0	0.0	46.4	0.0	5.2	109.6	83.5	0.0	180.0	424.7
Iowa	0.0	0.0	1.6	0.0	0.0	0.0	3.2	0.0	336.8	341.6
Kentucky	600.0	162.2	18.6	0.0	0.4	0.0	36.8	93.0	0.0	911.0
Louisiana	0.0	0.0	0.0	0.0	0.0	0.0	0.0	129.2	0.0	129.2
Maryland	65.0	0.0	12.7	129.0	0.0	0.0	878.3	15.0	0.3	1,100.3
Michigan	55.0	1.3	4.8	0.0	0.0	0.0	4.9	31.0	29.4	126.4
Missouri	0.0	0.0	5.6	0.0	0.0	0.0	19.6	0.0	451.0	476.2
New Jersey	0.0	0.0	43.5	0.0	11.6	0.0	2,048.2	0.0	4.8	2,108.2
New York	0.0	0.0	0.0	0.0	0.0	0.0	0.4	0.0	0.0	0.4
North Carolina	0.0	430.4	0.0	0.0	0.0	0.0	898.2	151.5	0.0	1,480.1
North Dakota	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	360.0	360.0
Ohio	0.0	6.6	30.8	52.0	14.2	32.4	194.1	92.8	47.4	470.4
Pennsylvania	109.7	31.7	45.2	88.5	15.1	5.0	336.9	8.6	3.3	643.8
South Carolina	0.0	0.0	30.8	0.0	0.0	0.0	0.0	0.0	0.0	30.8
Tennessee	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Texas	0.0	0.0	0.0	0.0	0.0	0.0	0.0	57.7	0.0	57.7
Virginia	0.0	17.9	11.3	0.0	3.1	0.0	123.1	287.6	0.0	443.0
West Virginia	0.0	0.0	0.0	0.0	0.0	0.0	4.1	0.0	0.0	4.1
Wisconsin	0.0	9.0	0.0	0.0	0.0	0.0	0.3	44.6	0.0	53.9
District of Columbia	0.0	0.0	0.0	0.0	49.4	0.0	59.4	0.0	0.0	108.8
Total	829.7	680.5	350.8	269.5	122.4	147.0	5,029.2	1,311.4	1,715.5	10,455.9

73 See PJM – EIS (Environmental Information Services), Generation Attribute Tracking System, "Renewable Generators Registered in GATS," <https://gats.pjm-eis.com/gats2/PublicReports/RenewableGeneratorsRegisteredinGATS>.

Renewable energy credits are related to the production and purchase of wholesale power, but have not, when they constitute a transaction separate from a wholesale sale of power, been found subject to FERC regulation.[74] RECs markets are, as an economic fact, integrated with PJM markets including energy and capacity markets, but are not formally recognized as part of PJM markets. Revenues from RECs markets are revenues for PJM resources earned in addition to revenues earned from the sale of the same MWh in PJM markets. FERC has found that such revenues can be appropriately considered in the rates established through the operation of wholesale organized markets.[75] This decision is an important recognition of the integration of the RECs markets and the other PJM markets.

Delaware, North Carolina, Michigan and Virginia allow various types of resources to earn multiple RECs per MWh, though typically one REC is equal to one MWh. For example, Delaware provided a three MWh REC for each MWh produced by in-state customer sited photovoltaic generation and fuel cells using renewable fuels that are installed on or before December 31, 2014.[76] This is equivalent to providing a REC price equal to three times its stated value per MWh. PJM Environmental Information Services (EIS), an unregulated subsidiary of PJM, operates the generation attribute tracking system (GATS), which is used by many jurisdictions to track these renewable energy credits.[77]

In addition to GATS, there are several other REC tracking systems used by states in the PJM footprint. Illinois, Indiana and Ohio use both GATS and M-RETS, the REC tracking system for resources located in the Midcontinent ISO, to track the sales of RECs used to fulfill their RPS requirements. Michigan and North Carolina have created their own state-wide tracking systems, MIRECS and NC-RETS, through which all RECs used to satisfy these states' RPS requirements must ultimately be traded. Table 8-10 shows the REC tracking systems used by each state within the PJM footprint.

Table 8-10 REC Tracking systems in PJM states with renewable portfolio standards

Jurisdiction with RPS	REC Tracking System Used			
Delaware	PJM-GATS			
Illinois	PJM-GATS	M-RETS		
Maryland	PJM-GATS			
Michigan			MIRECS	
New Jersey	PJM-GATS			
North Carolina				NC-RETS
Ohio	PJM-GATS	M-RETS		
Pennsylvania	PJM-GATS			
Washington, D.C.	PJM-GATS			
Jurisdiction with Voluntary Standard				
Indiana	PJM-GATS	M-RETS		
Virginia	PJM-GATS			

All PJM states with renewable portfolio standards have specified geographical restrictions governing the source of RECs to satisfy states' standards. Table 8-11 describes these restrictions. Indiana, Illinois, Michigan, and Ohio all have provisions in their renewables standards that require all or a portion of RECs used to comply with each state's standards to be generated by in-state resources. North Carolina has provisions that require RECs to be purchased from in-state resources but Dominion, the only utility located in both North Carolina and PJM, is exempt from these provisions. Pennsylvania added a provision in 2017 that requires SRECs used to comply with Pennsylvania's solar photovoltaics carve out standard to be sourced from resources located in Pennsylvania.

Pennsylvania requires that RECs used for compliance with its RPS are produced from resources located within the PJM footprint. Virginia requires that every load serving entity that chooses to participate in its voluntary renewable energy standard purchase RECs from the control area or RTO in which it is located. Delaware requires that RECs used for compliance with its RPS are produced from resources located within the PJM footprint or resources located elsewhere if these resources can demonstrate that the power they produce is directly deliverable to Delaware. The District of Columbia, Maryland and New Jersey allow RECs to be purchased from resources located within PJM in addition to large areas that adjoin PJM for compliance with their standards.

74 See *WSPP, Inc.*, 139 FERC ¶ 61,051 at P 18 (2012) ("we conclude that unbundled REC transactions fall outside of the Commission's jurisdiction under sections 201, 205 and 206 of the FPA. We further conclude that bundled REC transactions fall within the Commission's jurisdiction under sections 201, 205 and 206 of the FPA"); citing *American Ref-Fuel Company, et al.*, 105 FERC ¶ 61,004 at PP 23-24 (2003) ("American Ref-Fuel, 105 FERC ¶ 61,004 at PP 23-24 ("RECs are created by the States. They exist outside the confines of PURPA... And the contracts for sales of QF capacity and energy, entered into pursuant to PURPA, ... do not control the ownership of RECs."); see also *Williams Solar LLC and Allco Finance Limited*, 156 FERC ¶ 61,042 (2016).

75 See *ISO New England, Inc.*, 146 FERC ¶ 61,084 (2014) at P 32 ("We disagree with Exelon's argument that the Production Tax Credit and Renewable Energy Credits should be considered [out-of-market (OOM)] revenues. The relevant, Commission-approved Tariff provision defines OOM revenues as any revenues that are (i) not tradable throughout the New England Control Area or that are restricted to resources within a particular state or other geographic sub-region; or (ii) not available to all resources of the same physical type within the New England Control Area, regardless of the resource owner. [footnote omitted] Neither Production Tax Credit nor Renewable Energy Credits revenues fall within this definition.").

76 See DSIRE, NC Clean Energy Technology Center. Delaware Renewable Portfolio Standard, <http://programs.dsireusa.org/system/program/detail/1231> (Accessed November 3, 2018).

77 GATS publishes details on every renewable generator registered within the PJM footprint and aggregate emissions of renewable generation, but does not publish generation data by unit and does not make unit data available to the MMU.

Table 8-11 Geographic restrictions on REC purchases for renewable portfolio standard compliance in PJM states

State with RPS	RPS Contains In-state Provision	Geographical Requirements for RPS Compliance
Delaware	No	RECs must be purchased from resources located either within PJM or from resources outside of PJM that are directly deliverable into Delaware.
Illinois	Yes	All RECs must first be purchased from resources located within Illinois or resources located in a state directly adjoining Illinois. If there are insufficient RECs from Illinois and adjoining states to fulfill the RPS requirements, utilities may purchase RECs from anywhere.
Maryland	No	RECs must come from within PJM, 10-30 miles offshore the coast of Maryland or from a control area adjacent to PJM that is capable of delivering power into PJM.
Michigan	Yes	RECs must either come from resources located within Michigan or anywhere in the service territory of retail electric provider in Michigan that is not an alternative electric supplier. There are many exceptions to these requirements (see Michigan S.B. 213).
New Jersey	No	RECs must either be purchased from resources located within PJM or from resources located outside of PJM for which the energy associated with the REC is delivered to PJM via dynamic scheduling.
North Carolina	Yes	Dominion, the only utility located in both the state of North Carolina and PJM, may purchase RECs from anywhere. Other utilities in North Carolina not located in PJM are subject to different REC requirements (see G.S. 62-113.8).
Ohio	Yes	All RECs must be generated from resources that are located in the state of Ohio or have the capability to deliver power directly into Ohio. Any renewable facility located in a state contiguous to Ohio has been deemed deliverable into the state of Ohio. For renewable resources in noncontiguous states, deliverabilty must be demonstarted to the Public Utilities Commission of Ohio.
Pennsylvania	Yes	RECs must be purchased from resources located within PJM. All SRECs used for compliance with the Solar PV standard must source from solar PV resources within the state of Pennsylvania.
Washington, D.C.	No	RECs must be purchased from either a PJM state or a state adjacent with PJM. A PJM state is defined as any state with a portion of their geographical boundary within the footprint of PJM. An adjacent state is defined as a state that lies next to a PJM state, i.e. SC, GA, AL, AR, IA, NY, MO, MS, and WI.
State with Voluntary Standard		
Indiana	Yes	At least 50 percent of RECs must be purchased from resources located within Indiana.
Virginia	No	RECs must be purchased from the RTO or control area in which the participating utility is a member.

Carbon Pricing

Table 8-12 shows the impact of a range of carbon prices on the cost per MWh of producing energy from three basic unit types.[78] [79] For example, if the price of carbon were $50.00 per tonne, the short run marginal costs would increase by $25.04 per MWh for a new combustion turbine (CT) unit, $17.72 per MWh for a new combined cycle (CC) unit and $43.15 per MWh for a new coal plant (CP).

Table 8-12 Carbon price per MWh by unit type

	Carbon Price per MWh						
Unit Type	Carbon $5/tonne	Carbon $10/tonne	Carbon $15/tonne	Carbon $50/tonne	Carbon $100/tonne	Carbon $200/tonne	Carbon $400/tonne
CT	$2.50	$5.01	$7.51	$25.04	$50.08	$100.16	$200.33
CC	$1.77	$3.54	$5.32	$17.72	$35.45	$70.89	$141.78
CP	$4.32	$8.63	$12.95	$43.15	$86.30	$172.60	$345.21

Table 8-12 also illustrates the effective cost of carbon included in the price of a REC or SREC. For example, the average price of an SREC in New Jersey was $213.65 per MWh in 2018. The SREC price is paid in addition to the energy price paid at the time the solar energy is produced. If the MWh produced by the solar resource resulted in avoiding the production of a MWh from a CT, the value of carbon reduction implied by the SREC price is a carbon price of approximately $400 per tonne. This result also assumes that the entire value of the SREC was based on reduced carbon emissions. The SREC price consistent with a carbon price of $50.00 per tonne, assuming that a MWh from a CT is avoided, is $25.04 per MWh.

Applying this method to tier I REC and SREC price histories yields the implied carbon prices in Table 8-13. The carbon price implied by the 2018 average REC price in Ohio of $8.60 per tonne is higher than the RGGI clearing

78 Heat rates from: *2018 State of the Market Report for PJM*, Volume 2, Section 7: Net Revenue, Table 7-4.

79 Carbon emissions rates from: *Table A.3. Carbon Dioxide Uncontrolled Emission Factors*, Energy Information Administration, <https://www.eia.gov/electricity/annual/html/epa_a_03.html> (Accessed July 24, 2018).

price of $4.86 per tonne and lower than the social cost of carbon which is estimated in the range of $40 per tonne.[80] The carbon price implied by the 2018 average REC price in Washington, D.C. is $4.67 per tonne. The carbon prices implied by REC prices in Maryland, New Jersey, and Pennsylvania for 2018 are more consistent with the social cost of carbon than the RGGI price. The carbon prices implied by SREC prices have no apparent relationship to carbon prices implied by the REC clearing prices. Except for Pennsylvania, the carbon prices implied by SREC prices are significantly greater than the prices implied by REC prices in each jurisdiction and in some cases significantly higher than the social price of carbon.

solar credits be 200 percent of the average market value of solar RECs sold in the RTO plus the value of any solar rebates. For all states with an alternative compliance payment, the alternative compliance payment creates a cap on REC prices. The 2018 average SREC price in New Jersey was $213.65 compared to the alternative compliance payment level of $268.00 per MWh. In 2011, the solar alternative compliance payment level in New Jersey was $658 per MWh and as shown in Figure 8-7 New Jersey SREC prices exceeded $600 per MWh in 2011. Illinois requires that 50 percent of the state's renewable portfolio standard be met through alternative compliance payments. In Michigan and North Carolina, there are no pre-established values for alternative compliance payments. The public utility commissions in Michigan and North Carolina have the discretionary power to assess what a load serving entity must pay for any RPS shortfalls.

Table 8-14 shows the alternative compliance standards for RPS in PJM jurisdictions.

Table 8-13 Implied carbon price based on REC and SREC prices: 2009 through 2018[81 82]

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Jurisdiction with Tier I or Class I REC	**Carbon Price ($ per Metric Tonne) Implied by REC Prices**									
Delaware					$35.94	$36.94	$32.05	$33.24	$12.09	$11.74
Maryland	$2.03	$1.88	$3.00	$6.21	$17.10	$27.86	$30.40	$32.66	$34.53	$35.20
New Jersey	$13.07	$17.37	$8.40	$4.64	$12.82	$20.60	$24.77	$26.37	$23.51	$23.65
Ohio						$9.95	$8.34	$5.18	$6.14	$8.60
Pennsylvania	$6.68	$7.96	$3.26	$4.20	$15.54	$26.10	$29.55	$32.79	$34.67	$35.41
Washington, D.C.							$3.83	$4.31	$4.78	$4.67
Jurisdiction with Solar REC	**Carbon Price ($ per Metric Tonne) Implied by Solar REC Prices**									
Delaware						$114.81	$83.63	$84.69	$42.45	$56.91
Maryland		$534.77	$484.27	$374.62	$298.21	$286.62	$290.46	$286.56	$247.35	$206.38
New Jersey	$1,343.86	$1,324.06	$1,281.81	$525.92	$338.75	$319.44	$380.66	$415.40	$449.67	$426.60
Ohio						$80.61	$63.52	$68.09	$70.89	
Pennsylvania	$597.38	$578.30	$370.81	$99.69	$66.92	$74.33	$65.50	$53.91	$42.93	$17.71
Washington, D.C.	$698.17	$427.22	$491.20	$641.90	$936.69	$937.57	$973.40	$972.85	$848.18	$812.07
Regional Greenhouse Gas Initiative	**CO_2 Allowance Price ($ per Metric Tonne)**									
RGGI clearing price	$3.06	$2.12	$2.08	$2.13	$3.22	$5.21	$6.72	$4.93	$3.77	$4.86

Alternative Compliance Payments

PJM jurisdictions have various methods for complying with required renewable portfolio standards. If a retail supplier is unable to comply with the renewable portfolio standards required by the jurisdiction, suppliers may make alternative compliance payments, with varying standards, to cover any shortfall between the RECs required by the state and those the retail supplier actually purchased. In New Jersey, solar alternative compliance payments are $268.00 per MWh.[83] Pennsylvania requires that the alternative compliance payment for

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

81 The 2017 and 2018 weighted average procurement prices reported by the SREC Delaware Program were used in the derivation of the Delaware implied carbon price <http://www.srecdelaware.com/documentation/>. All other SREC prices used in the derivation of the implied carbon price are average annual prices obtained through Evomarkets, <http://www.evomarkets.com> (Accessed Jan. 23, 2018).

82 There were no trades in 2018 for Ohio SRECs available in the Evomarkets data.

83 N.J. S. 2314/A. 3723.

Table 8-14 Tier I and Tier II alternative compliance payments in PJM jurisdictions: December 31, 2018[84 85]

Jurisdiction with RPS	Standard Alternative Compliance ($/MWh)	Tier II Alternative Compliance ($/MWh)	Solar Alternative Compliance ($/MWh)
Delaware	$25.00		$400.00
Illinois	$1.89		
Maryland	$37.50	$15.00	$175.00
Michigan	No specific penalties		
New Jersey	$50.00		$268.00
North Carolina	No specific penalties: At the discretion of the NC Utility Commission		
Ohio	$51.31		$250.00
Pennsylvania	$45.00	$45.00	200% market value plus rebates
Washington, D.C.	$50.00	$10.00	$500.00
Jurisdiction with Voluntary Standard			
Indiana	Voluntary standard - No Penalties		
Virginia	Voluntary standard - No Penalties		
Jurisdiction with No Standard			
Kentucky	No standard		
Tennessee	No standard		
West Virginia	No standard		

Load serving entities participating in mandatory RPS programs in PJM jurisdictions must submit compliance reports to the relevant jurisdiction's public utility commission. In their submitted compliance reports, load serving entities must indicate the quantity of MWh that they have generated using eligible renewable or alternative energy resources. They must also identify the quantity of RECs they may have purchased to make up for renewable energy generation shortfalls or to comply with RPS provisions requiring that they purchase RECs. The public utility commissions then release RPS compliance reports to the public.

The Pennsylvania Public Utility Commission issued their 2017 compliance report for the Pennsylvania Alternative Energy Standards Act of 2004 during the first quarter of 2018.[86] Pennsylvania reported that the 20,634,311 credits retired during the compliance year exceeded the amount required by the standards by 1,995 credits. Not all suppliers met the required standard. Supplier obligations for six Tier I credits and 14 Tier II credits, were resolved through alternative compliance payments.

The Public Service Commission of the District of Columbia reported that 1,645,545 credits were retired during the 2017 compliance year and there was a significant increase in compliance payments.[87] Compliance payments were $26,571,010 for 2017, a 74.4 percent increase over the compliance payments for 2016. Solar standards contributed to the increase in compliance payments. Solar REC retirements in 2017 were 50.5 percent lower than solar REC retirements in 2016, with 30,765 solar RECs retired in 2017 and 62,173 retired in 2016.

The Public Service Commission of Maryland reported that "suppliers retired over 9.0 million RECs in 2017, slightly less than both the calculated obligation for the year and the 9.1 million RECs retired for compliance in 2016."[88] Alternative compliance payments totaled $55,032 for 2017 with the majority of payments "made in lieu of purchasing Tier 1 RECs to satisfy Industrial Load Process ("IPL") obligations."[89]

The Public Utilities Commission of Ohio reported that 2,682,588 non solar credits were retired in the 2016 compliance year, exceeding the credit obligation of 2,675,926 credits; and 135,146 solar credits were retired in the 2016 compliance year, exceeding the solar credit obligation of 134,828.[90] There were no alternative compliance payments for the 2016 compliance year.

Delmarva Power is the only retail electric supplier that must file a compliance report with the Delaware Public Service Commission. Delmarva Power reported to the Delaware Public Service Commission that they satisfied their REC obligation of 567,372 credits for the compliance year ending May 31, 2018 with zero

84 The Ohio standard alternative compliance payment (ACP) is updated annually <https://www.puco.ohio.gov/industry-information/industry-topics/acp-non-solar-alternative-compliance-payment-under-orc-492864/>. The Illinois Commerce Commission periodically publishes updates to the effective ACP amount <https://www.icc.illinois.gov/electricity/RPSCompliancePaymentNotices.aspx>. For updated Maryland ACPs, see Table 3 of the 2017 Renewable Energy Portfolio Standard Report <https://www.psc.state.md.us/commission-reports/>. Pennsylvania ACPs are described on p. 43 of the 2017 Annual Report on the Alternative Energy Portfolio Standard <https://www.pennaeps.com/reports/>.

85 See DSIRE, "Database of State Incentives for Renewables & Efficiency, "Policies & Incentives by State," <http://www.dsireusa.org/> (Accessed February 21, 2019).

86 "2017 Annual Report – Alternative Energy Portfolio Standards Act of 2004," (March 2018), <http://www.pennaeps.com/reports/>.

87 "Report on the Renewable Energy Portfolio Standard for Compliance Year 2017," Public Service Commission of the District of Columbia, (May 1, 2018), <https://www.dcpsc.org/Utility-Information/Electric/Renewables/Renewable-Energy-Portfolio-Standard-Program.aspx>.

88 "Renewable Energy Portfolio Standard Report," Public Service Commission of Maryland, p. 7, November 2018, <https://www.psc.state.md.us/wp-content/uploads/FINAL-Renewable-Energy-Portfolio-Standard-Report-with-data-for-CY-2017.pdf>.

89 Ibid., p. 8.

90 "Renewable Portfolio Standard Report to the General Assembly for Compliance Year 2016," Public Utilities Commission of Ohio, (February 21, 2019), <https://www.puco.ohio.gov/industry-information/industry-topics/ohioe28099s-renewable-and-advanced-energy-portfolio-standard/>.

alternative compliance payments.[91] Delmarva Power satisfied their solar REC obligation of 105,352 credits with zero alternative compliance payments.

The Illinois RPS requires electricity suppliers to satisfy at least 50 percent of their RPS obligation through alternative compliance payments. The Illinois Power Agency reported that most suppliers satisfied the remaining portion of their obligation for 2017 through the purchase of RECs rather than incur additional alternative compliance payments.[92]

The North Carolina Utilities Commission reported that all electric power suppliers met or appear to have met the 2017 renewable energy portfolio standard, solar energy requirement, and poultry waste energy requirement.[93 94] The implementation of the swine waste energy requirement has been delayed and electric power suppliers were not subject to the swine waste energy requirement for 2017.

The Michigan Public Service Commission reported that electric power suppliers met the 2017 renewable energy standards by retiring 10,218,115 RECs.[95]

New Jersey's Office of Clean Energy posted a summary of RPS compliance through the energy year ending May 31, 2018.[96] Electric power suppliers retired 9,166,102 class I RECs and 1,758,180 class II RECs. Alternative compliance payments were submitted for deficiencies of 24 class I credits and 9 class II credits. Electric power suppliers retired 2,357,814 solar RECs and there were no deficiencies requiring alternative compliance payments.

Emissions Controlled Capacity and Renewables in PJM Markets

Emission Controlled Capacity in the PJM Region

Environmental regulations affect decisions about emission control investments in existing units, investment in new units and decisions to retire units lacking emission controls.[97] Most PJM units burning fossil fuels have installed emission control technology. All coal steam units in PJM are compliant with the state and federal emissions limits established by MATS.

Coal has the highest SO_2 emission rate, while natural gas and diesel oil have lower SO_2 emission rates.[98] Of the current 67,952.7 MW of coal capacity in PJM, 63,602.4 MW of capacity, 93.6 percent, has some form of FGD (flue-gas desulfurization) technology to reduce SO_2 emissions. Table 8-15 shows SO_2 emission controls by fossil fuel fired units in PJM.[99 100 101]

Table 8-15 SO_2 emission controls by fuel type (MW): on December 31, 2018[102]

	SO_2 Controlled	No SO_2 Controls	Total	Percent Controlled
Coal	63,602.4	4,350.3	67,952.7	93.6%
Diesel Oil	0.0	5,379.6	5,379.6	0.0%
Natural Gas	0.0	75,741.0	75,741.0	0.0%
Other	325.0	4,805.7	5,130.7	6.3%
Total	63,927.4	90,276.6	154,204.0	41.5%

NO_X emission control technology is used by all fossil fuel fired unit types. Of current fossil fuel fired units in PJM, 145,309.8 MW, 94.2 percent, of 154,204.0 MW of capacity in PJM, have emission controls for NO_X. Table 8-16 shows NO_X emission controls by unit type in PJM. While most units in PJM have NO_X emission controls, many of these controls may need to be upgraded in order to meet each state's emission compliance standards based on whether a state is part of CSAPR, CAIR, Acid Rain Program (ARP) or a combination of the three.

91 "Retail Electricity Supplier's RPS Compliance Report, Compliance Period: June 1, 2016 – May 31, 2017," Delmarva Power, (Sept. 25, 2018), <https://depsc.delaware.gov/delawares-renewable-portfolio-standard-green-power-products/>.

92 "Annual Report Fiscal Year 2017," Illinois Power Agency, p. 44, (Feb. 15, 2018), <https://www2.illinois.gov/sites/ipa/Documents/Annual-Report-Illinois-Power-Agency-FY2017.pdf >.

93 "Annual Report Regarding Renewable Energy and Energy Efficiency Portfolio Standard in North Carolina," North Carolina Utilities Commission, (Oct. 1, 2018), <https://www.ncuc.net/Reps/reps.html>.

94 Ibid. at p. 53. Compliance plan approvals are pending for one municipally-owned electric utility and one electric membership corporation (EMC).

95 "Report on the Implementation and Cost-Effectiveness of the P.A. 295 Renewable Energy Standard," Michigan Public Service Commission, (Feb. 15, 2019), <https://www.michigan.gov/mpsc/0,4639,7-159-16393---,00.html>.

96 See RPS Report Summary 2005-2018, (Nov. 1, 2017), <http://www.njcleanenergy.com/renewable-energy/program-updates/rps-compliance-reports>.

97 See EPA. "National Ambient Air Quality Standards (NAAQS)," <https://www.epa.gov/criteria-air-pollutants/naaqs-table> (Accessed July 24, 2018).

98 Diesel oil includes number 1, number 2, and ultra-low sulfur diesel. See EPA. "Electronic Code of Federal Regulations, Title 40, Chapter 1, Subchapter C, Part 72, Subpart A Section 72.2," <http://www.ecfr.gov/cgi-bin/text-idx?SID=4f18612541a393473efb13acb879d470&mc=true&node=se40.18.72_12&rgn=div8> (Accessed July 24, 2018).

99 See EPA. "Air Market Programs Data," <http://ampd.epa.gov/ampd/> (Accessed February 12, 2019).

100 Air Markets Programs Data is submitted quarterly. Generators have 60 days after the end of the quarter to submit data, and all data is considered preliminary and subject to change until it is finalized in June of the following year.

101 The total MW are less than the 184,559.5 reported in Section 5: Capacity Market, because EPA data on controls could not be matched to some PJM units. "Air Markets Program Data," <http://ampd.epa.gov/ampd/QueryToolie.html> (Accessed Oct. 5, 2018).

102 The "other" category includes petroleum coke, wood, process gas, residual oil, other gas, and other oil. The EPA's "other" category does not have strict definitions for inclusion.

Future NO_X compliance standards will require selective catalytic reduction (SCRs) or selective non-catalytic reduction (SCNRs) for coal steam units, as well as SCRs or water injection technology for peaking combustion turbine units.[103]

Table 8-16 NO_X emission controls by fuel type (MW): on December 31, 2018

	NO_x Controlled	No NO_x Controls	Total	Percent Controlled
Coal	67,417.9	534.8	67,952.7	99.2%
Diesel Oil	1,612.6	3,767.0	5,379.6	30.0%
Natural Gas	73,627.6	2,113.4	75,741.0	97.2%
Other	2,651.7	2,479.0	5,130.7	51.7%
Total	145,309.8	8,894.2	154,204.0	94.2%

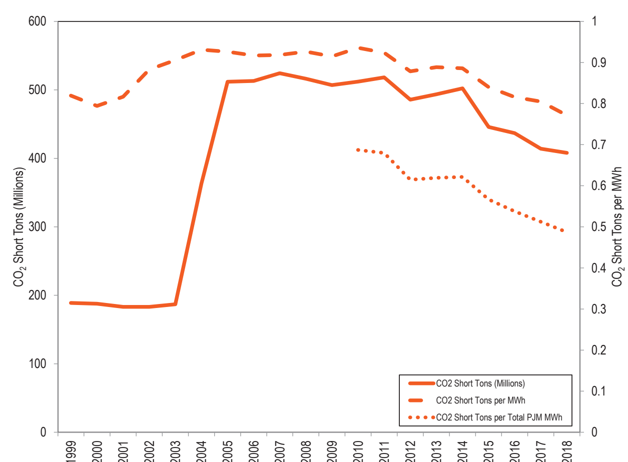
Most coal units in PJM have particulate controls. Typically, technologies such as electrostatic precipitators (ESP) or fabric filters (baghouses) are used to reduce particulate matter from coal steam units.[104] Fabric filters work by allowing the flue gas to pass through a tightly woven fabric which filters out the particulates. Table 8-17 shows particulate emission controls by unit type in PJM. In PJM, 67,618.7 MW out of 67,952.7 MW, 99.5 percent, of all coal steam unit MW, have some type of particulate emissions control technology, as of December 31, 2018. All coal steam units in PJM are compliant with the state and federal emissions limits established by MATS.[105] In order to achieve compliance with MATS, most coal steam units in PJM have particulate emission controls in the form of ESPs, but many units have also installed baghouse technology, or a combination of an FGD and SCR Currently, 154 of the 171 coal steam units have baghouse or FGD technology installed, representing 61,286.4 MW out of the 67,952.7 MW total coal capacity, or 90.2 percent.

Table 8-17 Particulate emission controls by fuel type (MW): on December 31, 2018

	Particulate Controlled	No Particulate Controls	Total	Percent Controlled
Coal	67,618.7	334.0	67,952.7	99.5%
Diesel Oil	0.0	5,379.6	5,379.6	0.0%
Natural Gas	2,786.0	72,955.0	75,741.0	3.7%
Other	2,970.5	2,160.2	5,130.7	57.9%
Total	73,375.2	80,828.8	154,204.0	47.6%

Figure 8-11 shows the total CO_2 short ton emissions (in millions) and the CO_2 short ton emissions per MWh within PJM, for all CO_2 emitting units, for each year from 1999 to 2018, as well as the CO_2 short ton emissions per MWh of total generation within PJM for 2010 to 2018.[106] Since 1999 the amount of CO_2 produced per MWh was at a minimum of 0.77 short tons per MWh in 2018, and a maximum of 0.94 short tons per MWh in 2010. In 2018, CO_2 emissions were 0.77 short tons per MWh. Total PJM generation increased from 808,229.7 GWh in 2017 to 837,648.3 GWh in 2018, while CO_2 produced decreased from 414.1 million tons in 2017 to 408.0 million tons in 2018.[107] The reduction in CO_2 emissions was primarily the result of a decrease in the use of coal and an increase in the use of natural gas for generation. Figure 8-12 shows the total on peak hour and off peak hour CO_2 short ton emissions (in millions) and the CO_2 short ton emissions per MWh within PJM, for all CO_2 emitting units, for 1999 to 2018. Since 1999 the amount of CO_2 produced per MWh during off peak hours was at a minimum of 0.78 short tons per MWh in 2018, and a maximum of 0.95 short tons per MWh in 2010. Since 1999 the amount of CO_2 produced per MWh during on peak hours was at a minimum of 0.76 short tons per MWh in 2018, and a maximum of 0.92 short tons per MWh in 2010. In 2018, CO_2 emissions were 0.78 short tons per MWh and 0.76 short tons per MWh for off and on peak hours.

Figure 8-11 CO_2 emissions by year (millions of short tons), by PJM units: 1999 through 2018[108] [109]



103 See EPA. "Mercury and Air Toxics Standards, Cleaner Power Plants," <https://www.epa.gov/mats/cleaner-power-plants#controls> (Accessed Oct. 5, 2018).

104 See EPA, "Air Pollution Control Technology Fact Sheet," <https://www3.epa.gov/ttn/catc/dir1/ff-pulse.pdf> (Accessed Oct. 5, 2018).

105 On April 14, 2016, the EPA issued a final finding regarding the Mercury and Air Toxics Standards. See EPA. "Regulatory Actions," <https://www.epa.gov/mats/regulatory-actions-final-mercury-and-air-toxics-standards-mats-power-plants> (Accessed Oct. 5, 2018).

106 Unless otherwise noted, emissions are measured in short tons. A short ton is 2,000 pounds.

107 See the *2018 State of the Market Report for PJM*, Section 3: Energy Market, Table 3-10.

108 The emissions are calculated from the continuous emission monitoring system (CEMS) data from generators located within the PJM footprint.

109 In 2004, PJM integrated the AEP, APS, ComEd, and DAY control zones. The large increase in total emissions in 2004 is a result of these integrations.

Figure 8-12 CO_2 emissions during on and off peak hours by year (millions of short tons), by PJM units: 1999 through 2018[110]

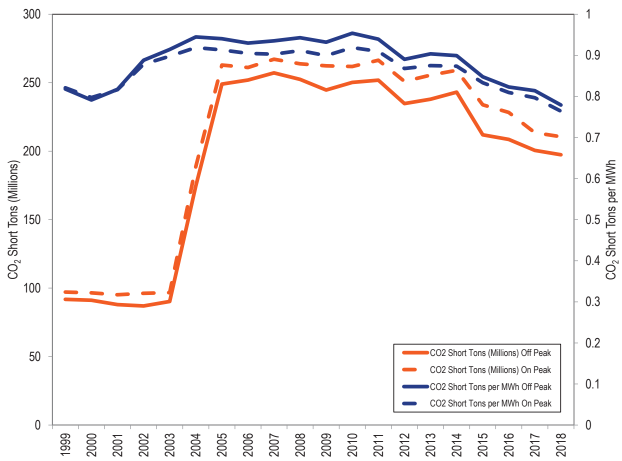
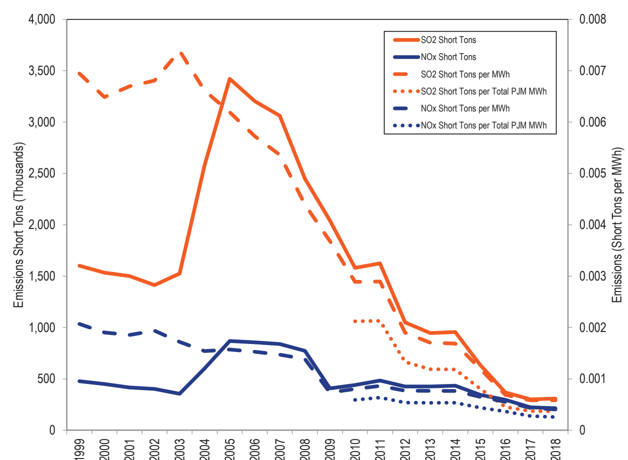


Figure 8-13 shows the total SO_2 and NO_X short ton emissions (in thousands) and the short ton emissions per MWh from emitting resources within PJM, for all SO_2 and NO_X emitting units, for 1999 to 2018, as well as the SO_2 and NO_X short ton emissions per MWh of total generation within PJM for 2010 to 2018. Since 1999 the amount of SO_2 produced per MWh was at a minimum of 0.000584 short tons per MWh in 2018, and a maximum of 0.007389 short tons per MWh in 2003. Since 1999, the amount of NO_X produced per MWh was at a minimum of 0.000406 short tons per MWh in 2018, and a maximum of 0.002070 short tons per MWh in 1999. In 2018, SO_2 emissions were 0.000584 short tons per MWh and NO_X emissions were 0.000406 short tons per MWh. The consistent decline in SO_2 and NO_X emissions starting in 2006 is the result of a decline in the use of coal, an increase in the use of natural gas, and the installation of environmental controls from 2006 to 2018.[111] [112]

Figure 8-14 shows the total on peak hour and off peak hour SO_2 and NO_X short ton emissions (in thousands) and the short ton emissions per MWh from emitting resources within PJM, for all SO_2 and NO_X emitting units, for each year from 1999 to 2018. Since 1999 the amount of SO_2 produced per MWh during off peak hours was at a minimum of 0.000571 short tons per MWh in 2017, and a maximum of 0.007583 short tons per MWh in 2003. Since 1999 the amount of SO_2 produced per MWh during on peak hours was at a minimum of 0.000587 short tons per MWh in 2018, and a maximum of 0.007211 short tons per MWh in 2003. Since 1999, the amount of NO_X produced per MWh during off peak hours was at a minimum of 0.000407 short tons per MWh in 2018, and a maximum of 0.002043 short tons per MWh in 1999. Since 1999, the amount of NO_X produced per MWh during on peak hours was at a minimum of 0.000404 short tons per MWh in 2018, and a maximum of 0.002095 short tons per MWh in 1999. In 2018, SO_2 emissions were 0.000580 short tons per MWh and 0.000588 short tons per MWh for off and on peak hours. In 2018, NO_X emissions were 0.000407 short tons per MWh and 0.000404 short tons per MWh for off and on peak hours.

Figure 8-13 SO_2 and NO_X emissions by year (thousands of short tons), by PJM units: 1999 through 2018[113]



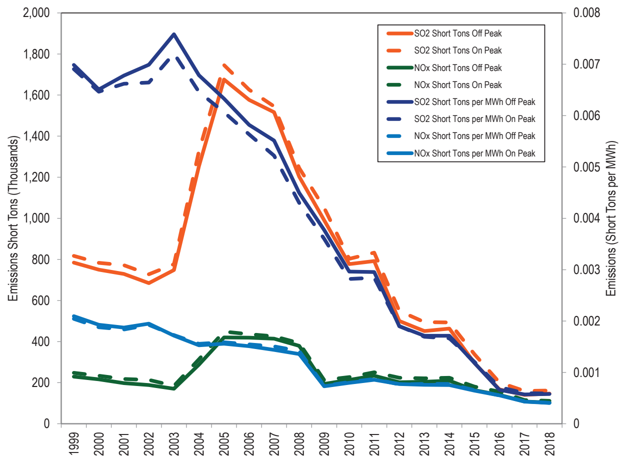
110 The emissions are calculated from the continuous emission monitoring system (CEMS) data from generators located within the PJM footprint.

111 See EIA, "Changes in coal sector led to less SO_2 and NO_x emissions from electric power industry," <https://www.eia.gov/todayinenergy/detail.php?id=37752> (Accessed March 1, 2019).

112 See EIA, "Sulfur dioxide emissions from U.S. power plants have fallen faster than coal generation," <https://www.eia.gov/todayinenergy/detail.php?id=29812> (Accessed March 1, 2019).

113 The emissions are calculated from the continuous emission monitoring system (CEMS) data from generators located within the PJM footprint.

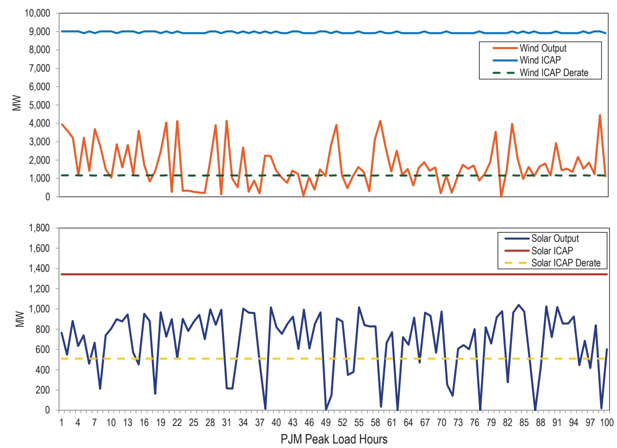
Figure 8-14 SO_2 and NO_X emissions during on and off peak hours by year (thousands of short tons), by PJM units: 1999 through 2018[114]



Wind and Solar Peak Hour Output

The capacity of solar and wind resources are derated for the PJM capacity market based on expected performance during high load hours. Figure 8-15 shows the wind and solar output during the top 100 load hours in PJM for 2018. The top 100 load hours in PJM during 2018, 93 are within PJM defined peak load periods. The hours are in descending order by load. The solid lines are the total ICAP of wind or solar PJM resources. The dashed lines are the total ICAP of wind and solar PJM resources derated to 13 and 38 percent.[115] The actual output of the wind and solar resources during the top 100 peak load hours ranges above and below the derated capacity (ICAP) values. Wind output was above the derated ICAP for 66 hours and below the derated ICAP for 34 hours of the top 100 peak load hours of 2018. The wind capacity factor for the top 100 peak load hours of 2018 was 19.0 percent. Wind output was above the derated ICAP for 6,301 hours and below the derated ICAP for 2,459 hours in 2018. The wind capacity factor for 2018 was 32.3 percent. Solar output was above the derated ICAP for 75 hours and below the derated ICAP for 25 hours of the top 100 peak load hours of 2018. The solar capacity factor for the top 100 peak load hours of 2018 was 50.7 percent. Solar output was above the derated ICAP for 2,020 hours and below the derated ICAP for 6,740 hours for 2018. The solar capacity factor for 2018 was YY percent.

Figure 8-15 Wind and solar output during the top 100 peak load hours in PJM: 2018



Wind Units

Table 8-18 shows the capacity factor of wind units in PJM. In 2018, the capacity factor of wind units in PJM was 32.3 percent. Wind units that were capacity resources had a capacity factor of 32.2 percent and an installed capacity of 7,869 MW. Wind units that were classified as energy only had a capacity factor of 33.9 percent and an installed capacity of 1,362 MW. Wind capacity in RPM is derated to 14.7 or 17.6 percent of nameplate capacity for the capacity market, based on the wind farm terrain, and energy only resources are not included in the capacity market.[116]

Table 8-18 Capacity factor of wind units in PJM: 2018[117]

Type of Resource	Capacity Factor	Installed Capacity (MW)
Energy-Only Resource	33.9%	1,362
Capacity Resource	32.2%	7,869
All Units	32.3%	9,230

Figure 8-16 shows the average hourly real-time generation of wind units in PJM, by month for January 1 through December 31, 2018. The hour with the highest average output, 4,228 MW, occurred in January, and the hour with the lowest average output, 805 MW, occurred in July. Wind output in PJM is generally higher in off-peak hours and lower in on-peak hours.

114 The emissions are calculated from the continuous emission monitoring system (CEMS) data from generators located within the PJM footprint.

115 PJM used derating factors of 13 and 38 percent until June 1, 2017. The current derating factors depend on installation type. PJM, Class Average Capacity Factors, <https://www.pjm.com/-/media/planning/res-adeq/class-average-wind-capacity-factors.ashx?la=en> (Accessed March 5, 2019).

116 PJM. Class Average Capacity Factors, <https://www.pjm.com/-/media/planning/res-adeq/class-average-wind-capacity-factors.ashx?la=en> (Accessed March 5, 2019).

117 Capacity factor is calculated based on online date of the resource.

Figure 8-16 Average hourly real-time generation of wind units in PJM: 2018

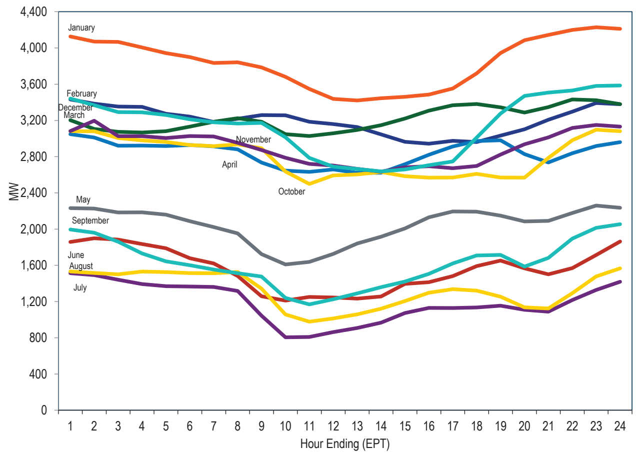


Figure 8-17 Average hourly day-ahead generation of wind units in PJM: 2018

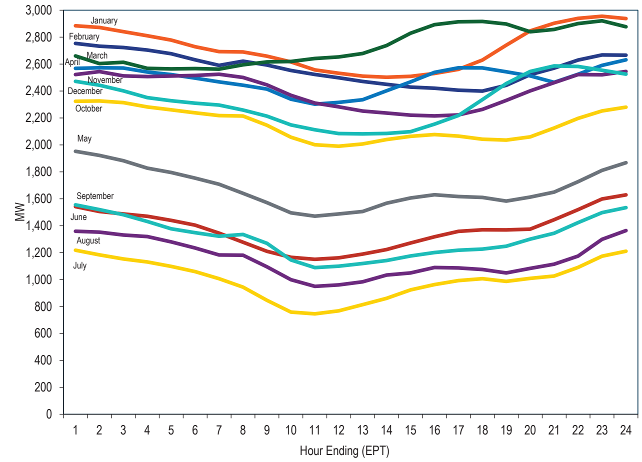


Table 8-19 shows the generation and capacity factor of wind units in each month of January 1, 2017 through December 31, 2018.

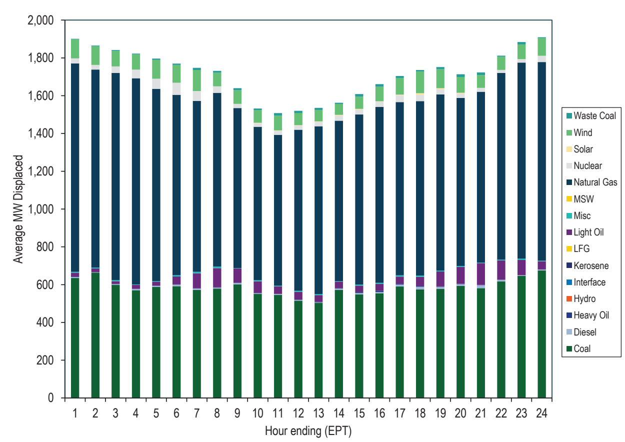
Table 8-19 Capacity factor of wind units in PJM by month: 2017 through 2018

	2017		2018	
Month	Generation (MWh)	Capacity Factor	Generation (MWh)	Capacity Factor
January	2,016,120.9	37.8%	2,856,292.5	48.3%
February	2,178,159.8	44.4%	2,148,206.1	40.4%
March	2,299,037.1	42.5%	2,387,719.3	41.7%
April	2,071,212.0	39.8%	2,044,167.0	37.7%
May	1,824,269.0	34.7%	1,519,815.5	27.5%
June	1,456,609.5	28.6%	1,117,467.9	21.1%
July	809,478.9	16.9%	881,491.2	16.8%
August	689,983.0	15.0%	984,116.9	19.0%
September	908,311.6	19.0%	1,164,672.2	22.1%
October	1,916,644.9	35.6%	2,081,941.6	35.8%
November	2,197,021.1	40.2%	2,089,084.0	35.7%
December	2,149,119.8	42.0%	2,332,656.7	37.3%
Annual	20,515,967.5	33.4%	21,607,630.8	32.3%

Wind units that are capacity resources are required, like all capacity resources except demand resources, to offer the energy associated with their cleared capacity in the Day-Ahead Energy Market and in the Real-Time Energy Market. Wind units may offer noncapacity related wind energy at their discretion. Figure 8-17 shows the average hourly day-ahead generation offers of wind units in PJM, by month. The hourly day-ahead generation offers of wind units in PJM may vary.

Output from wind turbines displaces output from other generation types. This displacement affects the output of marginal units in PJM. The magnitude and type of effect on marginal unit output depends on the level of the wind turbine output, its location, time and duration. One measure of this displacement is based on the mix of marginal units when wind is producing output. Figure 8-18 shows the hourly average proportion of marginal units by fuel type mapped to the hourly average MW of real-time wind generation in 2018. This is not an exact measure of displacement because it is not based on a redispatch of the system without wind resources. When wind appears as the displaced fuel at times when wind resources were on the margin this means that there was no displacement for those hours.

Figure 8-18 Marginal fuel at time of wind generation in PJM: 2018



Solar Units

Solar units in PJM may be in front of or behind the meter. The data reported include all PJM solar units that are in front of the meter. As shown in Table 8-8, there are 1,721.8 MW capacity of solar registered in GATS that are PJM units. As shown in Table 8-9, there are 5,029.2 MW capacity of solar registered in GATS that are not PJM capacity or energy resources. Some behind the meter generation exists in clusters, such as community solar farms, and serves dedicated customers. Such customers may or may not be located at the same node on the transmission system as the solar farm. When behind the meter generation and its associated load are at separate nodes, loads should pay for the appropriate level of transmission service, and should not be permitted to escape their proper financial responsibility through badly designed rules, such as rules for netting.

Table 8-20 shows the capacity factor of solar units in PJM. In 2018, the capacity factor of solar units in PJM was 22.1 percent. Solar units that were capacity resources had a capacity factor of 22.4 percent and an installed capacity of 1,302 MW. Solar units that were classified as energy only had a capacity factor of 19.7 percent and an installed capacity of 176 MW. Solar capacity in RPM is derated to 42.0, 60.0 or 38.0 percent of nameplate capacity for the capacity market, based on the installation type, and energy only resources are not included in the capacity market.[118]

Table 8-20 Capacity factor of solar units in PJM: 2018

Type of Resource	Capacity Factor	Installed Capacity (MW)
Energy-Only Resource	19.7%	176
Capacity Resource	22.4%	1,302
All Units	22.1%	1,477

Solar output differs from month to month, based on seasonal variation and daylight hours during the month. Figure 8-19 shows the average hourly real-time generation of solar units in PJM, by month. The hour with the highest peak average output, 877 MW, occurred in June, and the hour with the lowest peak average output, 506 MW, occurred in February. Solar output in PJM is highest during the hours of 11:00 through 13:00 EPT.

Figure 8-19 Average hourly real-time generation of solar units in PJM: 2018

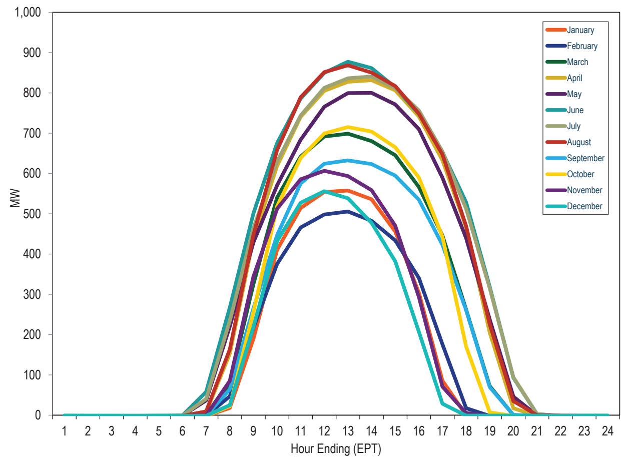


Table 8-21 shows the generation and capacity factor of solar units in each month of January 1, 2017 through December 31, 2018.

Table 8-21 Capacity factor of solar units in PJM by month: 2017 through 2018

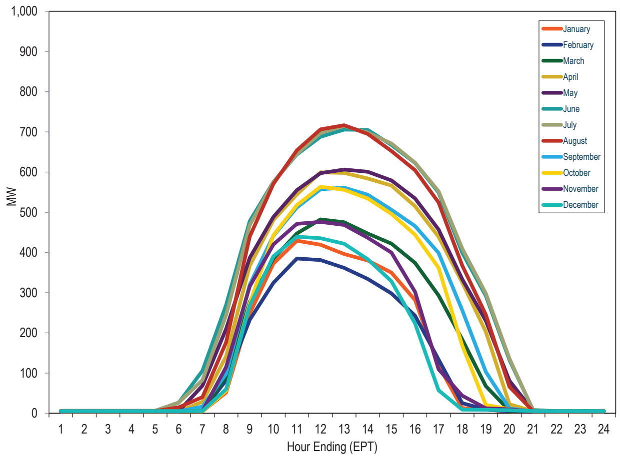
	2017		2018	
Month	Generation (MWh)	Capacity Factor	Generation (MWh)	Capacity Factor
January	47,456.3	11.6%	102,161.8	15.4%
February	84,111.1	21.7%	90,296.5	14.2%
March	109,498.1	25.0%	159,360.7	22.4%
April	121,835.3	27.5%	201,333.0	28.2%
May	127,944.3	26.9%	202,986.0	27.4%
June	146,226.0	30.5%	222,134.5	30.6%
July	144,300.0	28.6%	220,548.3	29.5%
August	133,780.1	26.3%	216,827.5	28.9%
September	125,731.7	25.4%	141,575.2	21.0%
October	104,658.9	19.1%	153,871.8	21.3%
November	90,442.5	16.3%	111,123.6	15.2%
December	61,707.8	12.0%	93,572.8	12.6%
Annual	1,297,692.0	22.5%	1,915,791.6	22.4%

Solar units that are capacity resources are required, like all capacity resources except demand resources, to offer the energy associated with their cleared capacity in the Day-Ahead Energy Market and in the Real-Time Energy Market. Solar units may offer noncapacity related solar energy at their discretion. Figure 8-20 shows the average hourly day-ahead generation offers of solar units in PJM, by month.[119]

118 PJM Class Average Capacity Factors, <https://www.pjm.com/-/media/planning/res-adeq/class-average-wind-capacity-factors.ashx?la=en> (Accessed March 5, 2019).

119 The average day-ahead generation of solar units in PJM is greater than 0 for hours when the sun is down due to some solar units being paired with landfill units.

Figure 8-20 Average hourly day-ahead generation of solar units in PJM: 2018



Interchange Transactions

PJM market participants import energy from, and export energy to, external regions continuously. The transactions involved may fulfill long-term or short-term bilateral contracts or respond to price differentials. The external regions include both market and nonmarket balancing authorities.

Overview

Interchange Transaction Activity

- **Aggregate Imports and Exports in the Real-Time Energy Market.** In 2018, PJM was a monthly net importer of energy in the Real-Time Energy Market in March and April, and a net exporter of energy in the remaining months.[1] In 2018, the real-time net interchange of -19,010.4 GWh was higher than the net interchange of -22,958.1 GWh in 2017.
- **Aggregate Imports and Exports in the Day-Ahead Energy Market.** In 2018, PJM was a monthly net importer of energy in the Day-Ahead Energy Market in March, April, May, June, July, August and November, and a net exporter of energy in the remaining months. In 2018, the total day-ahead net interchange of 2,977.4 GWh was higher than net interchange of -19,550.1 GWh in 2017.
- **Aggregate Imports and Exports in the Day-Ahead and the Real-Time Energy Market.** In 2018, gross imports in the Day-Ahead Energy Market were 290.3 percent of gross imports in the Real-Time Energy Market (184.9 percent in 2017). In 2018, gross exports in the Day-Ahead Energy Market were 126.1 percent of the gross exports in the Real-Time Energy Market (125.4 percent in 2017).
- **Interface Imports and Exports in the Real-Time Energy Market.** In 2018, there were net scheduled exports at 11 of PJM's 20 interfaces in the Real-Time Energy Market.[2]
- **Interface Pricing Point Imports and Exports in the Real-Time Energy Market.** In 2018, there were net scheduled exports at 12 of PJM's 18 interface pricing points eligible for real-time transactions in the Real-Time Energy Market.[3 4]
- **Interface Imports and Exports in the Day-Ahead Energy Market.** In 2018, there were net scheduled exports at 12 of PJM's 20 interfaces in the Day-Ahead Energy Market.[5]
- **Interface Pricing Point Imports and Exports in the Day-Ahead Energy Market.** In 2018, there were net scheduled exports at nine of PJM's 19 interface pricing points eligible for day-ahead transactions in the Day-Ahead Energy Market.[6]
- **Up To Congestion Interface Pricing Point Imports and Exports in the Day-Ahead Energy Market.** In 2018, up to congestion transactions were net exports at four of PJM's 19 interface pricing points eligible for day-ahead transactions in the Day-Ahead Energy Market.[7]
- **Inadvertent Interchange.** In 2018, net scheduled interchange was 19,010 GWh and net actual interchange was 18,351 GWh, a difference of 659 GWh. In 2017, the difference was 189 GWh. This difference is inadvertent interchange.
- **Loop Flows.** In 2018, the Northern Indiana Public Service (NIPS) Interface had the largest loop flows of any interface with 3 GWh of net scheduled interchange and -8,681 GWh of net actual interchange, a difference of 8,684 GWh. In 2018, the SouthIMP interface pricing point had the largest loop flows of any interface pricing point with 10,316 GWh of net scheduled interchange and 29,635 GWh of net actual interchange, a difference of 19,319 GWh.

1 Calculated values shown in Section 9, "Interchange Transactions," are based on unrounded, underlying data and may differ from calculations based on the rounded values in the tables.
2 In December 2018, PJM integrated OVEC, reducing the number of real-time interfaces to 19.
3 There is one interface pricing point eligible for day-ahead transaction scheduling only (NIPSCO).
4 In December 2018, PJM integrated OVEC, reducing the number of real-time interface pricing points to 17.
5 In December 2018, PJM integrated OVEC, reducing the number of day-ahead interfaces to 19.
6 In December 2018, PJM integrated OVEC, reducing the number of day-ahead interface pricing points to 18.
7 In December 2018, PJM integrated OVEC, reducing the number of day-ahead interface pricing points to 18.

Interactions with Bordering Areas

PJM Interface Pricing with Organized Markets

- **PJM and MISO Interface Prices.** In 2018, the direction of the hourly flow was consistent with the real-time hourly price differences between the PJM/MISO Interface and the MISO/PJM Interface in 56.8 percent of the hours.
- **PJM and New York ISO Interface Prices.** In 2018, the direction of the hourly flow was consistent with the real-time hourly price differences between the PJM/NYIS Interface and the NYISO/PJM proxy bus in 52.5 percent of the hours.
- **Neptune Underwater Transmission Line to Long Island, New York.** In 2018, the hourly flow (PJM to NYISO) was consistent with the real-time hourly price differences between the PJM Neptune Interface and the NYISO Neptune bus in 60.3 percent of the hours.
- **Linden Variable Frequency Transformer (VFT) Facility.** In 2018, the hourly flow (PJM to NYISO) was consistent with the real-time hourly price differences between the PJM Linden Interface and the NYISO Linden bus in 58.9 percent of the hours.
- **Hudson DC Line.** In 2018, the hourly flow (PJM to NYISO) was consistent with the real-time hourly price differences between the PJM Hudson Interface and the NYISO Hudson bus in 56.7 percent of the hours.

Interchange Transaction Issues

- **PJM Transmission Loading Relief Procedures (TLRs).** PJM issued five TLRs of level 3a or higher in 2018, compared to six such TLRs issued in 2017.
- **Up To Congestion.** On February 20, 2018, FERC issued an order limiting the eligible bidding points for up to congestion transactions to hubs, residual metered load and interfaces.[8] As a result, market participants reduced up to congestion trading effective February 22, 2018. The average number of up to congestion bids submitted in the Day-Ahead Energy Market decreased by 53.4 percent, from 138,489 bids per day in 2017 to 64,574 bids per day in 2018. The average cleared volume of up to congestion bids submitted in the Day-Ahead Energy Market decreased by 49.5 percent, from 838,258 MWh per day in 2017, to 422,981 MWh per day in 2018.
- **45 Minute Schedule Duration Rule.** Effective May 19, 2014, PJM removed the 45 minute scheduling duration rule in response to FERC Order No. 764.[9] [10] PJM and the MMU issued a statement indicating ongoing concern about market participants' scheduling behavior, and a commitment to address any scheduling behavior that raises operational or market manipulation concerns.[11]

Recommendations

- The MMU recommends that PJM implement rules to prevent sham scheduling. The MMU recommends that PJM apply after the fact market settlement adjustments to identified sham scheduling segments to ensure that market participants cannot benefit from sham scheduling. (Priority: High. First reported 2012. Status: Not adopted. Stakeholder process.)
- The MMU recommends that PJM implement a validation method for submitted transactions that would prohibit market participants from breaking transactions into smaller segments to defeat the interface pricing rule by concealing the true source or sink of the transaction. (Priority: Medium. First reported 2013. Status: Not adopted.)
- The MMU recommends that PJM implement a validation method for submitted transactions that would require market participants to submit transactions on paths that reflect the expected actual power flow in order to reduce unscheduled loop flows. (Priority: Medium. First reported 2013. Status: Not adopted.)
- The MMU recommends that PJM end the practice of maintaining outdated definitions of interface pricing points, eliminate the NIPSCO, Southeast and Southwest interface pricing points from the Day-Ahead and Real-Time Energy Markets and, with VACAR, assign the transactions created under the

8 162 FERC ¶ 61,139 (2018).

9 Order No. 764, 139 FERC ¶ 61,246 (2012), *order on reh'g*, Order No. 764-A, 141 FERC ¶ 61231 (2012).

10 *See* Letter Order, Docket No. ER14-381-000 (June 30, 2014).

11 *See* joint statement of PJM and the MMU re Interchange Scheduling issued July 29, 2014, at: <http://www.monitoringanalytics.com/reports/Market_Messages/Messages/PJM_IMM_Statement_on_Interchange_Scheduling_20140729.pdf>.

reserve sharing agreement to the SouthIMP/EXP pricing point. (Priority: Medium. First reported 2013. Status: Not adopted.)

- The MMU recommends that PJM eliminate the IMO interface pricing point, and assign the transactions that originate or sink in the IESO balancing authority to the MISO interface pricing point. (Priority: Medium. First reported 2013. Status: Not adopted.)
- The MMU recommends that PJM monitor, and adjust as necessary, the weights applied to the components of the interfaces to ensure that the interface prices reflect ongoing changes in system conditions. The MMU also recommends that PJM review the mappings of external balancing authorities to individual interface pricing points to reflect changes to the impact of the external power source on PJM tie lines as a result of system topology changes. The MMU recommends that this review occur at least annually. (Priority: Low. First reported 2009. Status: Not adopted.)
- The MMU recommends that, in order to permit a complete analysis of loop flow, FERC and NERC ensure that the identified data are made available to market monitors as well as other industry entities determined appropriate by FERC. (Priority: Medium. First reported 2003. Status: Not adopted.)
- The MMU recommends that PJM explore an interchange optimization solution with its neighboring balancing authorities that would remove the need for market participants to schedule physical transactions across seams. Such a solution would include an optimized, but limited, joint dispatch approach that uses supply curves and treats seams between balancing authorities as constraints, similar to other constraints within an LMP market. (Priority: Medium. First reported 2014. Status: Not adopted.)
- The MMU recommends that PJM permit unlimited spot market imports as well as unlimited nonfirm point-to-point willing to pay congestion imports and exports at all PJM interfaces in order to improve the efficiency of the market. (Priority: Medium. First reported 2012. Status: Not adopted.)
- The MMU recommends that PJM immediately provide the required 12-month notice to Duke Energy Progress (DEP) to unilaterally terminate the Joint Operating Agreement. (Priority: Low. First reported 2013. Status: Not adopted.)
- The MMU recommends that PJMSettlement 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. (Priority: Low. First reported 2015. Status: Not adopted.)
- The MMU recommends that the emergency interchange cap be replaced with a market based solution. (Priority: Low. First reported 2015. Status: Not adopted.)
- The MMU recommends that the submission deadline for real-time dispatchable transactions be modified from 1800 on the day prior, to three hours prior to the requested start time, and that the minimum duration be modified from one hour to 15 minutes. These changes would give PJM a more flexible product that could be used to meet load in the most economic manner. (Priority: Medium. First reported 2014. Status: Partially adopted, 2015.)

Conclusion

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

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

Interchange Transaction Activity

Charges and Credits Applied to Interchange Transactions

Interchange transactions are subject to various charges and credits. These charges and credits are dependent on whether the interchange transaction is submitted in the Real-Time or Day-Ahead Energy Market, the type of transaction, the transmission service used and whether the transaction is an import, export or wheel. Table 9-1 shows the billing line items that represent the charges and credits applied to real-time and day-ahead interchange transactions.[12]

Aggregate Imports and Exports

In December 2018, PJM integrated the Ohio Valley Electric Corporation (OVEC). This integration eliminated the OVEC Interface and the OVEC Interface Pricing Point from the real-time and day-ahead markets. Eleven shareholders own portions of the Clifty Creek and Kyger Creek generation and share OVEC's generation output. The majority of generation output is owned by load serving entities or their affiliates located in the PJM footprint. Prior to integration, the Clifty Creek and Kyger Creek units were pseudo tied to PJM. The Inter-Company Power Agreement (ICPA), signed by OVEC's shareholders, requires the continued delivery of the remaining generation output that is not designated to serve PJM to points external to the PJM footprint.[13] Prior to integration, the contractual obligation to provide the portion of the generation output to points external to the PJM footprint were block scheduled exports at the OVEC interface. After the OVEC integration, with the elimination of the OVEC Interface, the continued contractual obligation to provide the portion of the generation output to points external to the PJM footprint will be to block schedule exports at the LGEE Interface.

Table 9-1 Charges and credits applied to interchange transactions

	Real-Time Transactions				Day-Ahead Transactions				
Billing Item	Import (Firm or Non Firm)	Import (Spot in)	Export	Wheel	Import (Firm or Non Firm)	Import (Spot in)	Export	Wheel	Up to Congestion
Firm or Non-Firm Point-to-Point Transmission Service	X		X[1]	X[1]	X		X[1]	X[1]	
Spot Import Service		X[2]				X[2]			
Day-ahead Spot Market Energy					X	X	X		
Balancing Spot Market Energy	X	X	X						
Day-ahead Transmission Congestion					X	X	X	X	X
Balancing Transmission Congestion	X	X	X	X					X
Day-ahead Transmission Losses					X	X	X	X	X
Balancing Transmission Losses	X	X	X	X					X
PJM Scheduling, System Control and Dispatch Service - Control Area Administration	X		X	X	X		X	X	
PJM Scheduling, System Control and Dispatch Service - Market Support	X	X	X		X	X	X		X
PJM Scheduling, System Control and Dispatch Service - Advanced Second Control Center	X	X	X	X	X	X	X	X	X
PJM Scheduling, System Control and Dispatch Service - Market Support Offset	X	X	X		X	X	X		X
PJM Settlement, Inc.	X	X	X		X	X	X		X
Market Monitoring Unit (MMU) Funding	X	X	X		X	X	X		X
FERC Annual Recovery	X		X	X	X		X	X	
Organization of PJM States, Inc. (OPSI) Funding	X		X	X	X		X	X	
Synchronous Condensing			X				X		
Transmission Owner Scheduling, System Control and Dispatch Service	X		X	X	X		X	X	
Reactive Supply and Voltage Control from Generation and Other Sources Service	X		X	X	X		X	X	
Day-ahead Operating Reserve					X	X	X		
Balancing Operating Reserve	X	X	X						
Black Start Service	X		X	X	X		X	X	
Marginal Loss Surplus Allocation (for those paying for transmission service only)			X				X		

1 No charge if Point of Delivery is MISO

2 No charge for spot in transmission

12 For an explanation and current rate for each billing line item, see "*Customer Guide to PJM Billing*" (January 1, 2019) <http://www.pjm.com/~/media/markets-ops/settlements/custgd.ashx>.

13 See "Ohio Valley Electric Corporation: Company Background," <http://www.ovec.com/OVECHistory.pdf> (October 15, 2014).

In 2018, PJM was a monthly net importer of energy in the Real-Time Energy Market in March and April, and a net exporter of energy in the remaining months (Figure 9-1).[14] In 2018, the total real-time net interchange of -19,010.4 GWh was higher than the net interchange of -22,958.1 GWh in 2017. In 2018, the peak month for net exporting interchange was December, -2,772.4 GWh; in 2017 it was July, -2,559.2 GWh. Gross monthly export volumes in 2018 averaged 2,951.5 GWh compared to 3,209.9 GWh in 2017, while gross monthly imports in 2018 averaged 1,367.3 GWh compared to 1,296.7 GWh in 2017.

In 2018, PJM was a monthly net importer of energy in the Day-Ahead Energy Market in March, April, May, June, July, August and November, and a net exporter of energy in the remaining months (Figure 9-1).

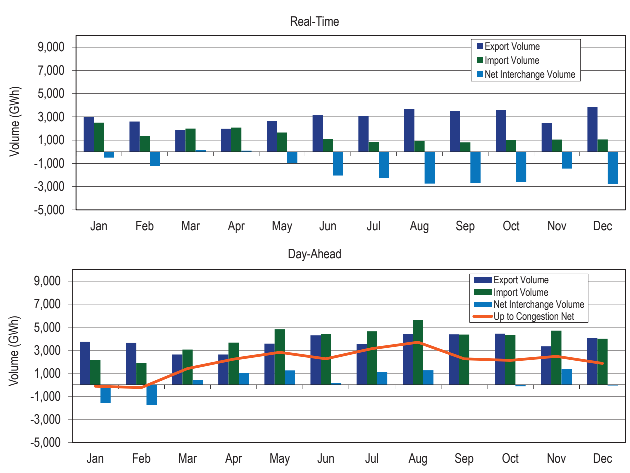
On February 20, 2018, FERC issued an order limiting the eligible bidding points for up to congestion transactions to hubs, residual metered load[15] [16] and interfaces.[17] As a result, market participants reduced up to congestion trading effective February 22, 2018. The majority of up to congestion transaction volume is between internal buses, so while there was a significant decrease in up to congestion trading, the impact on the day-ahead net interchange was not as large. While the internal up to congestion transaction volume decreased by 54.9 percent, from 19,790.7 GWh in January to 8,921.7 GWh in December (Table 9-12), the gross import up to congestion volume increased by 112.1 percent, from 1,726.8 GWh in January to 3,662.8 GWh in December (Table 9-14) and the gross export up to congestion volume decreased by 2.2 percent, from 1,854.8 GWh in January to 1,813.7 GWh in December (Table 9-16). In 2018, the total day-ahead net interchange of 2,977.4 GWh was higher than the net interchange of -19,550.1 GWh in 2017. In 2018, the peak month for net exporting interchange was February, -1,739.4 GWh; in 2017 it was August, -2,236.3 GWh. Gross monthly export volumes in 2018 averaged 3,721.7 GWh compared to 4,026.6 GWh in 2017, while gross monthly imports in 2018 averaged 3,969.8 GWh compared to 2,397.4 GWh in 2017.

Figure 9-1 shows real-time and day-ahead import, export and net interchange volumes. The day-ahead totals include fixed, dispatchable and up to congestion transaction totals. The net interchange of up to congestion transactions are represented by the orange line.

In 2018, gross imports in the Day-Ahead Energy Market were 290.3 percent of gross imports in the Real-Time Energy Market (184.9 percent in 2017). In 2018, gross exports in the Day-Ahead Energy Market were 126.1 percent of gross exports in the Real-Time Energy Market (125.4 percent in 2017). In 2018, net interchange was 2,977.4 GWh in the Day-Ahead Energy Market and -19,010.4 GWh in the Real-Time Energy Market compared to -19,550.1 GWh in the Day-Ahead Energy Market and -22,958.1 GWh in the Real-Time Energy Market in 2017.

Transactions in the Day-Ahead Energy Market create financial obligations to deliver in the Real-Time Energy Market and to pay operating reserve charges based on differences between the transaction MWh in the Day-Ahead and Real-Time Energy Markets times the applicable operating reserve rates.[18] In 2018, the total day-ahead gross imports and exports were higher than the real-time gross imports and exports, the day-ahead imports net of up to congestion transactions were less than the real-time imports, and the day-ahead exports net of up to congestion transactions were less than real-time exports.

Figure 9-1 Scheduled imports and exports: 2018



14 Calculated values shown in Section 9, "Interchange Transactions," are based on unrounded, underlying data and may differ from calculations based on the rounded values in the tables.

15 A Residual Metered Load aggregate represents all load buses in a fully metered EDC territory, minus all load that has been designated to be priced at specific non-zonal (or nodal) locations.

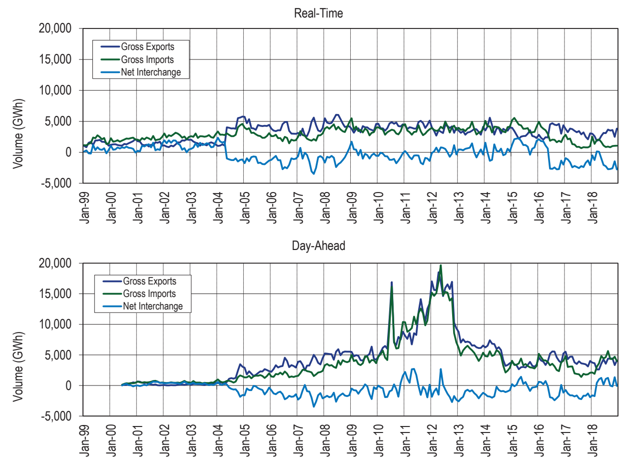
16 For more information on Residual Metered Load aggregates, see *Residual Metered Load Aggregate Pricing FAQ* (June 3, 2015) at: <http://www.pjm.com/~/media/markets-ops/energy/residual-metered-load-pricing/residual-metered-load-aggregate-pricing-faq.ashx>.

17 162 FERC ¶ 61,139 (2018).

18 Up to congestion transactions create financial obligations to deliver in real time, but do not pay operating reserve charges.

Figure 9-2 shows the real-time and day-ahead import and export volume for PJM from 1999 through 2018. PJM shifted from a consistent net importer of energy to relatively consistent net exporter of energy in 2004 in both the Real-Time and Day-Ahead Energy Markets, coincident with the expansion of the PJM footprint that included the integrations of Commonwealth Edison, American Electric Power and Dayton Power and Light into PJM. The net direction of power flows is generally a function of price differences net of transactions costs. Since the modification of the up to congestion product in September 2010, up to congestion transactions have played a significant role in power flows between PJM and external balancing authorities in the Day-Ahead Energy Market. On November 1, 2012, PJM eliminated the requirement that every up to congestion transaction include an interface pricing point as either the source or sink. As a result, the volume of import and export up to congestion transactions decreased, and the volume of internal up to congestion transactions increased. While the gross import and export volumes in the Day-Ahead Energy Market decreased, PJM has remained primarily a net exporter in the Day-Ahead Energy Market. The requirement for external capacity resources to be pseudo tied into PJM has affected the real-time and day-ahead import volumes. Prior to June 1, 2016, these units were dynamically scheduled into PJM or were block scheduled into PJM and were part of scheduled interchange as imports. Pseudo tied units are treated as internal generation and therefore do not affect interchange volume. The reduction of the import volume based on the switch to pseudo tie status contributed to PJM remaining a net exporter in the Real-Time and Day-Ahead Energy Markets. The changes in up to congestion bidding behavior resulting from the February 20, 2018, FERC order limiting the eligible bidding points for up to congestion transactions to hubs, residual metered load and interfaces contributed to PJM becoming a net importer in the Day-Ahead Energy Market starting in March, 2018.

Figure 9-2 Scheduled import and export transaction volume history: 1999 through 2018



Real-Time Interface Imports and Exports

In the Real-Time Energy Market, scheduled imports and exports are defined by the scheduled path, which is the transmission path a market participant selects from the original source to the final sink. These scheduled flows are measured at each of PJM's interfaces with neighboring balancing authorities. Table 9-17 includes a list of active interfaces in 2018. Figure 9-3 shows the approximate geographic location of the interfaces. In 2018, PJM had 20 interfaces with neighboring balancing authorities.[19] While the Linden (LIND) Interface, the Hudson (HUDS) Interface and the Neptune (NEPT) Interface are separate from the NYIS Interface, all four are interfaces between PJM and the NYISO. Similarly, there are 10 separate interfaces that make up the MISO Interface between PJM and MISO. Table 9-2 through Table 9-4 show the real-time energy market scheduled interchange totals at the individual NYISO interfaces, as well as with the NYISO as a whole. Similarly, the scheduled interchange totals at the individual interfaces between PJM and MISO are shown, as well as with MISO as a whole. Net scheduled interchange in the Real-Time Energy Market is shown by interface for 2018 in Table 9-2, while gross scheduled imports and exports are shown in Table 9-3 and Table 9-4.

In the Real-Time Energy Market, in 2018, there were net scheduled exports at 11 of PJM's 20 interfaces. The top three net exporting interfaces in the Real-Time Energy

19 In December 2018, PJM integrated OVEC, reducing the number of real-time interfaces to 19.

Market accounted for 57.3 percent of the total net scheduled exports: PJM/Cinergy (CIN) with 19.4 percent, PJM/MidAmerican Energy Company (MEC) with 19.2 percent and PJM/Neptune (NEPT) with 18.8 percent of the net scheduled export volume. The four separate interfaces that connect PJM to the NYISO (PJM/NYIS, PJM/NEPT, PJM/HUDS and PJM/Linden (LIND)) together represented 46.4 percent of the total net PJM scheduled exports in the Real-Time Energy Market. There were net scheduled exports in the Real-Time Energy Market at five of the 10 separate interfaces that connect PJM to MISO. Those five exporting interfaces represented 52.1 percent of the total net PJM scheduled exports in the Real-Time Energy Market.

In the Real-Time Energy Market, in 2018, there were net scheduled imports at eight of PJM's 20 interfaces. The top three importing interfaces in the Real-Time Energy Market accounted for 80.7 percent of the total net scheduled imports: PJM/Ameren-Illinois (AMIL) with 44.9 percent, PJM/LG&E Energy, L.L.C. (LGEE) with 24.4 percent and PJM/Duke Energy Corp. (DUK) with 11.4 percent of the net scheduled import volume.[20] The four separate interfaces that connect PJM to the NYISO (PJM/NYIS, PJM/NEPT, PJM/HUDS and PJM/Linden (LIND)) had net scheduled exports in the Real-Time Energy Market. There were net scheduled imports in the Real-Time Energy Market at four of the 10 separate interfaces that connect PJM to MISO. Those four interfaces represented 57.3 percent of the total net PJM scheduled imports in the Real-Time Energy Market.

Table 9-2 Real-time scheduled net interchange volume by interface (GWh): 2018

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
CPLE	(125.2)	58.6	141.4	216.6	99.1	60.8	64.4	63.1	(82.7)	(37.8)	41.2	(39.9)	459.5
CPLW	(6.0)	0.0	6.5	1.5	2.3	0.0	0.0	0.0	0.3	0.2	0.0	0.0	4.8
DUK	(232.4)	209.7	14.4	3.5	199.9	156.1	140.4	152.1	(109.1)	210.9	140.6	(114.3)	771.8
LGEE	347.9	121.5	103.8	183.1	153.8	178.6	158.8	141.0	62.1	79.6	104.2	22.8	1,657.2
MISO	552.2	(625.7)	509.7	286.1	(1,250.8)	(1,670.0)	(1,210.5)	(1,319.8)	(945.8)	(1,491.4)	(905.6)	(1,487.3)	(9,559.0)
ALTE	(105.3)	(355.0)	80.9	9.5	(430.4)	(568.6)	(359.8)	(325.8)	(199.4)	(275.8)	(126.2)	(139.9)	(2,795.7)
ALTW	0.0	0.0	0.1	0.5	(2.7)	0.0	0.0	(4.3)	(3.3)	(1.0)	0.6	0.0	(10.2)
AMIL	626.4	307.7	511.5	463.6	266.5	152.6	77.7	99.2	198.1	154.7	129.9	58.4	3,046.3
CIN	(81.4)	(345.9)	17.8	(205.0)	(690.7)	(547.3)	(373.3)	(527.1)	(400.9)	(744.6)	(390.4)	(703.9)	(4,992.5)
CWLP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
IPL	64.2	(25.6)	8.4	6.6	(84.5)	(85.5)	(55.5)	(100.9)	(88.9)	(126.8)	(84.1)	(116.1)	(688.9)
MEC	(294.0)	(250.0)	(342.9)	(376.1)	(433.7)	(444.5)	(461.1)	(454.4)	(432.2)	(466.6)	(453.8)	(550.4)	(4,959.7)
MECS	355.2	82.0	224.1	285.3	82.1	(208.7)	(32.5)	(11.9)	(56.4)	(51.3)	31.6	(10.8)	688.8
NIPS	0.0	0.4	5.0	0.2	0.0	0.0	(0.0)	(1.9)	0.0	(0.0)	0.0		2.6
WEC	(12.9)	(39.3)	4.9	101.5	42.6	32.0	(6.0)	7.3	37.3	20.1	(13.2)	(23.7)	150.4
NYISO	(1,065.2)	(1,075.9)	(782.0)	(820.0)	(292.4)	(701.3)	(1,350.9)	(1,662.5)	(1,498.3)	(883.8)	(644.4)	(1,191.8)	(11,968.5)
HUDS	(73.3)	(189.9)	(159.5)	(144.1)	(8.5)	(63.3)	(238.6)	(329.0)	(299.5)	(204.5)	(140.4)	(142.6)	(1,993.1)
LIND	(169.7)	(166.1)	(183.8)	(86.6)	(55.5)	(125.6)	(124.1)	(174.0)	(190.4)	(84.9)	(179.6)	(221.1)	(1,761.3)
NEPT	(376.5)	(437.1)	(431.1)	(443.6)	(299.0)	(377.7)	(464.8)	(485.6)	(473.2)	(492.2)	(80.6)	(475.4)	(4,836.8)
NYIS	(445.6)	(282.8)	(7.7)	(145.8)	70.7	(134.8)	(523.4)	(673.9)	(535.3)	(102.3)	(243.8)	(352.6)	(3,377.3)
OVEC	(22.0)	(17.9)	(17.6)	(12.4)	(12.0)	(12.1)	(12.8)	(13.9)	(12.7)	(12.9)	(13.7)	NA	(160.2)
TVA	52.9	81.3	159.8	236.1	120.3	(53.7)	(27.0)	(96.4)	(108.2)	(449.8)	(169.5)	38.1	(216.1)
Total	(497.8)	(1,248.4)	136.0	94.3	(979.8)	(2,041.6)	(2,237.7)	(2,736.5)	(2,694.4)	(2,585.1)	(1,447.1)	(2,772.4)	(19,010.4)

20 In the Real-Time Energy Market, one PJM interface had a net interchange of zero (PJM/City Water Light & Power (CWLP)).

Table 9-3 Real-time scheduled gross import volume by interface (GWh): 2018

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
CPLE	66.9	72.3	194.1	244.8	143.6	113.9	92.9	104.1	28.2	41.8	135.5	62.0	1,300.0
CPLW	0.1	0.0	6.5	1.5	2.3	0.0	0.0	0.0	0.3	0.2	0.0	0.0	10.9
DUK	117.7	275.4	30.2	12.8	214.3	243.1	210.6	195.5	152.0	309.7	277.6	267.5	2,306.3
LGEE	353.3	131.5	103.9	183.1	153.8	178.6	159.0	141.0	62.2	114.4	104.2	119.2	1,804.1
MISO	1,528.6	646.3	1,321.7	1,219.8	773.9	396.4	205.3	316.7	374.7	315.6	266.7	292.9	7,658.5
ALTE	185.8	108.7	191.9	147.3	62.2	22.8	21.9	56.7	27.8	12.6	22.4	46.9	906.9
ALTW	0.0	0.0	0.1	0.5	0.0	0.0	0.0	0.4	0.2	0.2	0.6	0.0	1.9
AMIL	627.0	308.5	511.6	467.4	270.1	161.5	77.7	108.5	198.1	154.7	130.0	120.3	3,135.3
CIN	173.5	39.6	294.2	137.7	33.3	42.0	16.7	7.3	29.5	50.2	36.5	26.0	886.2
CWLP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
IPL	76.5	6.5	27.4	23.9	11.4	3.0	1.8	0.7	2.7	1.2	1.8	3.5	160.5
MEC	55.1	47.4	56.0	52.9	47.4	26.0	19.3	22.4	28.1	23.2	19.1	20.3	417.1
MECS	402.2	135.3	229.7	286.9	291.2	65.4	50.3	85.1	37.4	28.4	45.7	66.1	1,723.9
NIPS	0.0	0.4	5.0	0.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	5.6
WEC	8.5	0.0	5.9	103.0	58.3	75.7	17.5	35.6	51.0	45.2	10.6	9.7	421.1
NYISO	255.1	124.4	152.0	164.6	228.7	113.3	121.8	122.8	125.8	161.1	137.5	142.0	1,849.0
HUDS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.0	0.0	0.4
LIND	16.6	1.1	4.6	16.5	20.8	2.8	7.3	2.0	6.0	11.0	3.1	1.0	92.7
NEPT	0.1	0.0	0.0	0.0	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.3
NYIS	238.3	123.3	147.4	148.1	207.8	110.4	114.4	120.7	119.7	150.1	134.4	141.0	1,755.5
OVEC	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	NA	0.0
TVA	183.7	101.7	183.0	254.6	143.1	48.7	66.8	49.4	66.6	78.3	126.8	176.1	1,478.6
Total	2,505.3	1,351.6	1,991.3	2,081.2	1,659.6	1,093.9	856.3	929.4	809.8	1,021.0	1,048.2	1,059.7	16,407.4

Table 9-4 Real-time scheduled gross export volume by interface (GWh): 2018

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
CPLE	192.1	13.7	52.7	28.2	44.5	53.2	28.5	41.0	110.9	79.6	94.2	101.9	840.5
CPLW	6.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	6.1
DUK	350.1	65.7	15.8	9.4	14.5	86.9	70.2	43.4	261.1	98.8	137.0	381.8	1,534.5
LGEE	5.4	10.0	0.0	0.0	0.0	0.0	0.2	0.0	0.1	34.9	0.0	96.4	146.9
MISO	976.4	1,272.1	812.0	933.7	2,024.7	2,066.3	1,415.8	1,636.4	1,320.5	1,807.0	1,172.3	1,780.3	17,217.5
ALTE	291.1	463.7	111.0	137.8	492.6	591.4	381.7	382.5	227.1	288.4	148.6	186.8	3,702.6
ALTW	0.0	0.0	0.0	0.0	2.7	0.0	0.0	4.7	3.6	1.1	0.0	0.0	12.1
AMIL	0.6	0.8	0.1	3.8	3.6	8.9	0.0	9.3	0.0	0.0	0.1	61.8	89.1
CIN	254.8	385.5	276.4	342.6	723.9	589.2	390.0	534.4	430.4	794.8	426.8	729.9	5,878.8
CWLP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
IPL	12.4	32.2	19.0	17.4	95.9	88.4	57.3	101.6	91.6	128.0	85.9	119.6	849.4
MEC	349.0	297.3	398.9	429.0	481.2	470.5	480.5	476.7	460.2	489.8	472.9	570.7	5,376.7
MECS	47.0	53.3	5.6	1.6	209.0	274.1	82.8	97.0	93.9	79.7	14.1	76.9	1,035.1
NIPS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.9	0.0	0.0	0.0	1.0	3.0
WEC	21.4	39.3	1.0	1.6	15.8	43.7	23.5	28.3	13.7	25.1	23.9	33.5	270.7
NYISO	1,320.2	1,200.3	934.0	984.6	521.0	814.6	1,472.7	1,785.3	1,624.1	1,044.9	781.9	1,333.9	13,817.4
HUDS	73.3	189.9	159.5	144.1	8.5	63.3	238.7	329.0	299.6	204.5	140.4	142.6	1,993.5
LIND	186.3	167.2	188.3	103.1	76.2	128.4	131.4	176.0	196.4	95.8	182.7	222.1	1,854.0
NEPT	376.7	437.1	431.1	443.6	299.1	377.8	464.8	485.6	473.2	492.2	80.6	475.4	4,837.1
NYIS	683.9	406.1	155.1	293.8	137.1	245.2	637.8	794.6	655.0	252.3	378.2	493.7	5,132.8
OVEC	22.0	17.9	17.6	12.4	12.0	12.1	12.8	13.9	12.7	12.9	13.7	NA	160.2
TVA	130.8	20.4	23.2	18.5	22.8	102.4	93.8	145.8	174.8	528.1	296.2	138.0	1,694.7
Total	3,003.0	2,600.0	1,855.3	1,986.9	2,639.5	3,135.5	3,094.0	3,665.9	3,504.1	3,606.0	2,495.3	3,832.1	35,417.8

Real-Time Interface Pricing Point Imports and Exports

Interfaces differ from interface pricing points. An interface is a point of interconnection between PJM and a neighboring balancing authority which market participants may designate as a path on which scheduled imports or exports will flow.[21] An interface pricing point defines the price at which transactions are priced, and is based on the path of the actual, physical transfer of energy. While a market participant designates a scheduled path from a generation control area (GCA) to a load control area (LCA), this path reflects the scheduled path as defined by the transmission reservations only, and may not reflect how the energy actually flows from the GCA to LCA. For example, the import transmission path from LG&E Energy, L.L.C. (LGEE), through MISO and into PJM would show the

21 There are multiple paths between any generation and load balancing authority. Market participants select the path based on transmission service availability and the transmission costs for moving energy from generation to load and interface prices.

transfer of power into PJM at the PJM/MISO Interface based on the scheduled path of the transaction. However, the physical flow of energy does not enter the PJM footprint at the PJM/MISO Interface, but enters PJM at the southern boundary. For this reason, PJM prices an import with the GCA of LGEE at the SouthIMP interface pricing point rather than the MISO pricing point.

Interfaces differ from interface pricing points. The challenge is to create interface prices, composed of external pricing points, which accurately represent the locational price impact of flows between PJM and external sources of energy and that reflect the underlying economic fundamentals across balancing authority borders.[22]

Transactions can be scheduled to an interface based on a contract transmission path, but pricing points are developed and applied based on the estimated electrical impact of the external power source on PJM tie lines, regardless of the contract transmission path.[23] PJM establishes prices for transactions with external balancing authorities by assigning interface pricing points to individual balancing authorities based on the generation control area and load control area as specified on the NERC Tag. Dynamic interface pricing calculations use actual system conditions to determine a set of weights for each external pricing point in an interface price definition. The weights are designed so that the interface price reflects actual system conditions. However, the weights are an approximation given the complexity of the transmission network outside PJM and the dynamic nature of power flows. Table 9-18 presents the interface pricing points used in 2018. On September 16, 2014, PJM updated the mappings of external balancing authorities to individual pricing points. The MMU recommends that PJM review these mappings, at least annually, to reflect the fact that changes to the system topology can affect the impact of external power sources on PJM.

The interface pricing method implies that the weighting factors reflect the actual system flows in a dynamic manner. In fact, the weightings are static, and are modified by PJM only occasionally.[24] The MMU recommends that PJM monitor, and adjust as necessary, the weights applied to the components of the interfaces to ensure that the interface prices reflect ongoing changes in system conditions.

The contract transmission path only reflects the path of energy into or out of PJM to one neighboring balancing authority. The NERC Tag requires the complete path to be specified from the generation control area (GCA) to the load control area (LCA), but participants do not always do so. The NERC Tag path is used by PJM to determine the interface pricing point that PJM assigns to the transaction. This approach will correctly identify the interface pricing point only if the market participant provides the complete path in the Tag. This approach will not correctly identify the interface pricing point if the market participant breaks the transaction into portions, each with a separate Tag. The breaking of transactions into portions can be a way to manipulate markets and the result of such behavior can be incorrect and noncompetitive pricing of transactions.

There are several pricing points mapped to the region south of PJM. The SouthIMP and SouthEXP pricing points serve as the default pricing point for transactions at the southern border of PJM. The CPLEEXP, CPLEIMP, DUKEXP, DUKIMP, NCMPAEXP and NCMPAIMP were also established to account for various special agreements with neighboring balancing areas, and PJM continued to use the Southwest pricing point for certain grandfathered transactions which have since expired.[25]

In the Real-Time Energy Market, in 2018, there were net scheduled exports at 12 of PJM's 18 interface pricing points eligible for real-time transactions.[26] [27] The top three net exporting interface pricing points in the Real-Time Energy Market accounted for 74.7 percent of the total net scheduled exports: PJM/MISO with 49.3 percent, PJM/NEPTUNE with 15.0 percent and PJM/NYIS with 10.5 percent of the net scheduled export volume. The four separate interface pricing points that connect PJM to the NYISO (PJM/NYIS, PJM/NEPTUNE, PJM/HUDSONTP and PJM/LINDENVFT) together represented 37.1 percent of the total net PJM scheduled exports in the Real-Time Energy Market.

22 See the *2007 State of the Market Report for PJM*, Volume 2, Appendix D, "Interchange Transactions," for a more complete discussion of the development of pricing points.

23 See "Interface Pricing Point Assignment Methodology" (August 28, 2014) <http://www.pjm.com/~/media/etools/exschedule/interface-pricing-point-assignment-methodology.ashx>. PJM periodically updates these definitions on its website.

24 On June 1, 2015, PJM began using a dynamic weighting factor in the calculation for the Ontario Interface Pricing Point.

25 Use of the Southwest pricing point for grandfathered transactions is not appropriate, and the MMU recommends that no further such agreements be entered into.

26 There is one interface pricing point eligible for day-ahead transaction scheduling only (NIPSCO).

27 In December 2018, PJM integrated OVEC, reducing the number of real-time interface pricing points to 17.

In the Real-Time Energy Market, in 2018, there were net scheduled imports at five of PJM's 18 interface pricing points eligible for real-time transactions. The top two net importing interface pricing points in the Real-Time Energy Market accounted for 89.3 percent of the total net scheduled imports: PJM/SouthIMP with 77.8 percent and PJM/Ontario Independent Electricity System Operator (IMO) with 11.6 percent of the net scheduled import volume. The four separate interface pricing points that connect PJM to the NYISO (PJM/NYIS, PJM/NEPTUNE, PJM/HUDSONTP and PJM/LINDENVFT) had net scheduled exports in the Real-Time Energy Market.[28]

Table 9-5 Real-time scheduled net interchange volume by interface pricing point (GWh): 2018

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
IMO	545.9	179.2	184.4	135.9	79.2	37.2	61.8	105.1	37.6	25.7	42.5	97.8	1,532.4
MISO	(793.5)	(1,187.6)	(414.6)	(728.8)	(1,940.2)	(2,026.8)	(1,382.9)	(1,576.7)	(1,265.3)	(1,756.6)	(1,110.2)	(1,719.1)	(15,902.2)
NORTHWEST	(0.3)	0.0	(0.2)	(1.9)	(0.4)	(0.0)	0.0	0.0	0.0	(0.1)	0.0	0.0	(2.9)
NYISO	(1,064.6)	(1,074.4)	(781.2)	(820.0)	(295.7)	(702.8)	(1,350.5)	(1,662.5)	(1,498.7)	(884.6)	(644.4)	(1,190.5)	(11,969.9)
HUDSONTP	(73.3)	(189.9)	(159.5)	(144.1)	(8.5)	(63.3)	(238.6)	(329.0)	(299.5)	(204.5)	(140.4)	(142.6)	(1,993.1)
LINDENVFT	(169.7)	(166.1)	(183.8)	(86.6)	(55.5)	(125.6)	(124.1)	(174.0)	(190.4)	(84.9)	(179.6)	(221.1)	(1,761.3)
NEPTUNE	(376.5)	(437.1)	(431.1)	(443.6)	(299.0)	(377.7)	(464.8)	(485.6)	(473.2)	(492.2)	(80.6)	(475.4)	(4,836.8)
NYIS	(445.0)	(281.3)	(6.9)	(145.8)	67.4	(136.3)	(523.0)	(673.9)	(535.7)	(103.0)	(243.8)	(351.3)	(3,378.7)
OVEC	(22.0)	(17.9)	(17.6)	(12.4)	(12.0)	(12.1)	(12.8)	(13.9)	(12.7)	(12.9)	(13.7)	NA	(160.2)
Southern Imports	1,521.4	964.5	1,257.9	1,578.1	1,271.0	905.8	641.2	642.2	591.9	790.1	810.5	759.3	11,733.8
CPLEIMP	2.2	0.1	0.2	0.0	0.0	0.0	0.0	0.0	0.1	0.0	0.0	0.0	2.7
DUKIMP	7.8	6.0	37.8	37.4	43.9	80.8	13.7	9.3	13.6	6.9	25.9	20.1	303.1
NCMPAIMP	83.3	131.4	85.7	104.3	111.5	90.9	89.4	85.6	49.5	98.6	73.5	108.6	1,112.4
SOUTHEAST	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHWEST	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHIMP	1,428.1	826.9	1,134.2	1,436.4	1,115.5	734.1	538.1	547.2	528.7	684.6	711.1	630.6	10,315.6
Southern Exports	(684.7)	(112.2)	(92.7)	(56.4)	(81.8)	(242.8)	(194.5)	(230.7)	(547.2)	(746.8)	(531.8)	(719.9)	(4,241.5)
CPLEEXP	(57.7)	(0.7)	(10.4)	(12.2)	(19.1)	(17.6)	(17.3)	(5.9)	(23.1)	(6.9)	(28.7)	(36.3)	(235.9)
DUKEXP	(101.6)	(47.2)	(19.0)	(2.2)	(0.3)	(23.5)	(35.2)	(16.9)	(98.4)	(29.8)	(65.6)	(256.0)	(695.8)
NCMPAEXP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	(0.0)	0.0	0.0	0.0	(0.0)
SOUTHEAST	(0.9)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	(0.9)
SOUTHWEST	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHEXP	(524.6)	(64.3)	(63.3)	(42.0)	(62.3)	(201.7)	(142.0)	(207.8)	(425.6)	(710.1)	(437.4)	(427.6)	(3,308.9)
Total	(497.8)	(1,248.4)	136.0	94.3	(979.8)	(2,041.6)	(2,237.7)	(2,736.5)	(2,694.4)	(2,585.1)	(1,447.1)	(2,772.4)	(19,010.4)

Table 9-6 Real-time scheduled gross import volume by interface pricing point (GWh): 2018

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
IMO	547.5	182.8	188.1	136.2	79.5	37.2	68.1	121.7	49.6	25.7	44.1	101.6	1,582.0
MISO	181.3	79.9	393.4	202.4	83.8	39.2	25.3	42.7	42.9	44.9	56.2	56.8	1,248.8
NORTHWEST	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
NYISO	255.1	124.4	151.8	164.6	225.3	111.8	121.8	122.8	125.4	160.3	137.4	142.0	1,842.7
HUDSONTP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.0	0.0	0.4
LINDENVFT	16.6	1.1	4.6	16.5	20.8	2.8	7.3	2.0	6.0	11.0	3.1	1.0	92.7
NEPTUNE	0.1	0.0	0.0	0.0	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.3
NYIS	238.3	123.3	147.2	148.1	204.5	108.9	114.4	120.7	119.3	149.3	134.4	141.0	1,749.3
OVEC	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	NA	0.0
Southern Imports	1,521.4	964.5	1,257.9	1,578.1	1,271.0	905.8	641.2	642.2	591.9	790.1	810.5	759.3	11,733.8
CPLEIMP	2.2	0.1	0.2	0.0	0.0	0.0	0.0	0.0	0.1	0.0	0.0	0.0	2.7
DUKIMP	7.8	6.0	37.8	37.4	43.9	80.8	13.7	9.3	13.6	6.9	25.9	20.1	303.1
NCMPAIMP	83.3	131.4	85.7	104.3	111.5	90.9	89.4	85.6	49.5	98.6	73.5	108.6	1,112.4
SOUTHEAST	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHWEST	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHIMP	1,428.1	826.9	1,134.2	1,436.4	1,115.5	734.1	538.1	547.2	528.7	684.6	711.1	630.6	10,315.6
Southern Exports	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CPLEEXP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DUKEXP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
NCMPAEXP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHEAST	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHWEST	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHEXP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total	2,505.3	1,351.6	1,991.3	2,081.2	1,659.6	1,093.9	856.3	929.4	809.8	1,021.0	1,048.2	1,059.7	16,407.4

28 In the Real-Time Energy Market, one PJM interface pricing point had a net interchange of zero (Southwest).

Table 9-7 Real-time scheduled gross export volume by interface pricing point (GWh): 2018

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
IMO	1.5	3.6	3.7	0.3	0.3	0.0	6.3	16.6	12.0	0.0	1.6	3.8	49.6
MISO	974.8	1,267.5	808.1	931.2	2,024.0	2,066.0	1,408.2	1,619.4	1,308.2	1,801.4	1,166.4	1,775.9	17,151.1
NORTHWEST	0.3	0.0	0.2	1.9	0.4	0.0	0.0	0.0	0.0	0.1	0.0	0.0	2.9
NYISO	1,319.7	1,198.8	933.0	984.6	521.0	814.6	1,472.2	1,785.3	1,624.1	1,044.9	781.8	1,332.6	13,812.6
HUDSONTP	73.3	189.9	159.5	144.1	8.5	63.3	238.7	329.0	299.6	204.5	140.4	142.6	1,993.5
LINDENVFT	186.3	167.2	188.3	103.1	76.2	128.4	131.4	176.0	196.4	95.8	182.7	222.1	1,854.0
NEPTUNE	376.7	437.1	431.1	443.6	299.1	377.8	464.8	485.6	473.2	492.2	80.6	475.4	4,837.1
NYIS	683.3	404.6	154.0	293.8	137.1	245.2	637.4	794.6	655.0	252.3	378.2	492.3	5,128.0
OVEC	22.0	17.9	17.6	12.4	12.0	12.1	12.8	13.9	12.7	12.9	13.7	NA	160.2
Southern Imports	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CPLEIMP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DUKIMP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
NCMPAIMP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHEAST	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHWEST	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHIMP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Southern Exports	684.7	112.2	92.7	56.4	81.8	242.8	194.5	230.7	547.2	746.8	531.8	719.9	4,241.5
CPLEEXP	57.7	0.7	10.4	12.2	19.1	17.6	17.3	5.9	23.1	6.9	28.7	36.3	235.9
DUKEXP	101.6	47.2	19.0	2.2	0.3	23.5	35.2	16.9	98.4	29.8	65.6	256.0	695.8
NCMPAEXP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHEAST	0.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.9
SOUTHWEST	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHEXP	524.6	64.3	63.3	42.0	62.3	201.7	142.0	207.8	425.6	710.1	437.4	427.6	3,308.9
Total	3,003.0	2,600.0	1,855.3	1,986.9	2,639.5	3,135.5	3,094.0	3,665.9	3,504.1	3,606.0	2,495.3	3,832.1	35,417.8

Day-Ahead Interface Imports and Exports

In the Day-Ahead Energy Market, as in the Real-Time Energy Market, scheduled imports and exports are determined by the scheduled path, which is the transmission path a market participant selects from the original source to the final sink. Entering external energy transactions in the Day-Ahead Energy Market requires fewer steps than in the Real-Time Energy Market. Market participants need to acquire a valid, willing to pay congestion (WPC) OASIS reservation to prove that their day-ahead schedule could be supported in the Real-Time Energy Market.[29] Day-ahead energy market schedules need to be cleared through the day-ahead energy market process in order to become an approved schedule. The day-ahead energy market transactions are financially binding, but will not physically flow unless they are also submitted in the Real-Time Energy Market. In the Day-Ahead Energy Market, a market participant is not required to acquire a ramp reservation, a NERC Tag, or to go through a neighboring balancing authority checkout process.

There are three types of day-ahead external energy transactions: fixed; up to congestion; and dispatchable.[30]

29 Effective September 17, 2010, up to congestion transactions no longer required a willing to pay congestion transmission reservation.

30 See the *2010 State of the Market Report for PJM*, Volume 2, Section 4, "Interchange Transactions," for details.

In the Day-Ahead Energy Market, transaction sources and sinks are determined solely by market participants. In Table 9-8, Table 9-9, and Table 9-10, the scheduled interface designation is determined by the transmission reservation that was acquired and associated with the day-ahead market transaction, and does not bear any necessary relationship to the pricing point designation selected at the time the transaction is submitted to PJM in real time. For example, if market participants want to import energy from the Southwest Power Pool (SPP) to PJM, they are likely to choose a scheduled path with the fewest transmission providers along the path and therefore the lowest transmission costs for the transaction, regardless of whether the resultant path is related to the physical flow of power. The lowest cost transmission path runs from SPP, through MISO, and into PJM, requiring only three transmission reservations, two of which are available at no cost (MISO transmission would be free based on the regional through and out rates, and the PJM transmission would be free, if using spot import transmission). Any other transmission path entering PJM, where the generating control area is to the south, would require the market participant to acquire transmission through nonmarket balancing authorities, and thus incur additional transmission costs. PJM's interface pricing method recognizes that transactions sourcing in SPP and sinking in PJM will create flows across the southern border and prices those transactions at the SouthIMP interface price. As a result, a market participant who plans to submit a transaction from SPP to PJM may have a transmission reservation with a point of receipt of MISO and a point of delivery of PJM but may select SouthIMP as the import pricing point when submitting the transaction in the Day-Ahead Energy Market. In the scheduled interface tables, the import transaction would appear as scheduled through the MISO Interface, and in the scheduled interface pricing point tables, the import transaction would appear as scheduled through the SouthIMP/EXP interface pricing point, which reflects the expected power flow.

Table 9-8 through Table 9-10 show the day-ahead scheduled interchange totals at the individual interfaces. Net scheduled interchange in the Day-Ahead Energy Market is shown by interface for 2018 in Table 9-8, while gross scheduled imports and exports are shown in Table 9-9 and Table 9-10.

In the Day-Ahead Energy Market, in 2018, there were net scheduled exports at 12 of PJM's 20 interfaces.[31] The top three net exporting interfaces in the Day-Ahead Energy Market accounted for 63.0 percent of the total net scheduled exports: PJM/MidAmerican Energy Company (MEC) with 23.8 percent, PJM/Neptune (NEPT) with 21.3 percent, and PJM/NYIS with 17.9 percent of the net scheduled export volume. The four separate interfaces that connect PJM to the NYISO (PJM/NYIS, PJM/NEPT, PJM/HUDS and PJM/Linden (LIND)) together represented 46.4 percent of the total net PJM scheduled exports in the Day-Ahead Energy Market. In 2018, there were net exports in the Day-Ahead Energy Market at seven of the 10 separate interfaces that connect PJM to MISO. Those seven interfaces represented 50.9 percent of the total net PJM exports in the Day-Ahead Energy Market.

In the Day-Ahead Energy Market, in 2018, there were net scheduled imports at five of PJM's 20 interfaces. The top two net importing interfaces in the Day-Ahead Energy Market accounted for 99.1 percent of the total net scheduled imports: PJM/CPLE[32] with 51.9 percent and PJM/Duke Energy Corp. (DUK) with 47.3 percent of the net scheduled import volume. The four separate interfaces that connect PJM to the NYISO (PJM/NYIS, PJM/NEPT, PJM/HUDS and PJM/Linden (LIND)) had net scheduled exports in the Day-Ahead Energy Market. In 2018, there were net imports in the Day-Ahead Energy Market at one of the 10 separate interfaces that connect PJM to MISO (Northern Indiana Public Service (NIPS). That one interface represented 5.5 percent of the total net PJM imports in the Day-Ahead Energy Market.[33]

31 In December 2018, PJM integrated OVEC, reducing the number of day-ahead interfaces to 19.
32 The Progress Energy Carolinas (PEC) LMP is defined as the Carolina Power and Light (East) (CPLE) pricing point.
33 In the Day-Ahead Energy Market, three PJM interfaces had a net interchange of zero (PJM/Ameren Illinois (AMIL), PJM/City Water Light & Power (CWLP) and PJM/Ohio Valley Electric Cooperative (OVEC)).

Table 9-8 Day-ahead scheduled net interchange volume by interface (GWh): 2018

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
CPLE	61.4	86.5	110.6	111.9	98.8	68.4	105.7	149.8	23.0	12.1	88.1	53.8	970.0
CPLW	0.0	0.0	1.2	7.8	0.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	9.5
DUK	(9.0)	181.2	38.1	35.9	56.1	66.6	54.0	73.3	7.2	152.4	152.5	75.9	884.4
LGEE	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.3	1.3
MISO	(585.9)	(787.9)	(445.1)	(694.2)	(1,426.2)	(1,568.9)	(967.4)	(1,090.0)	(874.0)	(1,214.4)	(778.7)	(1,142.5)	(11,575.3)
ALTE	(244.8)	(386.0)	44.7	(62.4)	(418.7)	(399.2)	(268.7)	(291.4)	(158.2)	(244.4)	(83.0)	(148.3)	(2,660.5)
ALTW	0.0	0.0	0.0	0.0	0.0	0.0	0.0	(4.6)	(4.6)	(0.3)	0.0	0.0	(9.4)
AMIL	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CIN	(50.2)	(99.1)	(125.3)	(215.7)	(364.8)	(287.9)	(126.0)	(211.1)	(148.0)	(375.2)	(194.7)	(390.2)	(2,588.4)
CWLP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
IPL	0.0	0.0	0.0	0.0	0.0	0.0	0.0	(1.5)	(0.8)	0.0	0.0	0.0	(2.3)
MEC	(348.6)	(299.3)	(398.9)	(426.4)	(481.3)	(576.4)	(481.6)	(475.7)	(461.1)	(488.5)	(470.6)	(511.3)	(5,419.7)
MECS	82.3	36.2	28.6	11.9	(146.5)	(261.6)	(68.1)	(77.2)	(90.1)	(84.1)	(7.5)	(61.7)	(637.9)
NIPS	0.0	(1.2)	6.7	0.0	0.0	0.0	(0.0)	0.0	0.0	0.0	0.0	0.0	5.5
WEC	(24.6)	(38.6)	(0.9)	(1.6)	(14.8)	(43.7)	(22.9)	(28.5)	(11.2)	(21.9)	(22.9)	(31.0)	(262.7)
NYISO	(982.1)	(975.4)	(706.6)	(747.8)	(339.6)	(614.1)	(1,193.0)	(1,495.4)	(1,319.4)	(837.9)	(404.5)	(942.4)	(10,558.3)
HUDS	(65.3)	(161.1)	(144.4)	(106.8)	(0.8)	(45.0)	(190.5)	(277.5)	(252.5)	(151.3)	(73.6)	(85.5)	(1,554.3)
LIND	(18.9)	(27.7)	(27.4)	(13.0)	(4.1)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	(91.1)
NEPT	(366.6)	(439.1)	(436.6)	(428.0)	(300.3)	(382.4)	(469.7)	(496.0)	(477.8)	(493.4)	(78.8)	(478.5)	(4,847.3)
NYIS	(531.3)	(347.5)	(98.2)	(200.0)	(34.3)	(186.6)	(532.8)	(721.9)	(589.1)	(193.2)	(252.2)	(378.5)	(4,065.7)
OVEC	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	NA	0.0
TVA	35.1	3.1	23.1	88.4	37.7	(76.5)	(47.1)	(77.7)	(103.0)	(362.9)	(162.0)	39.0	(602.8)
Total without Up To Congestion	(1,480.5)	(1,492.6)	(978.6)	(1,198.0)	(1,572.7)	(2,124.4)	(2,047.7)	(2,440.0)	(2,266.3)	(2,250.8)	(1,104.7)	(1,915.0)	(20,871.4)
Up To Congestion	(128.0)	(246.8)	1,409.1	2,222.9	2,818.1	2,254.8	3,140.0	3,689.3	2,252.0	2,118.4	2,470.0	1,849.1	23,848.8
Total	(1,608.5)	(1,739.4)	430.5	1,024.9	1,245.3	130.4	1,092.2	1,249.4	(14.3)	(132.4)	1,365.3	(65.9)	2,977.4

Table 9-9 Day-ahead scheduled gross import volume by interface (GWh): 2018

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
CPLE	89.7	94.8	131.8	133.2	133.0	97.9	123.8	171.4	67.6	75.7	141.5	110.1	1,370.6
CPLW	0.0	0.0	1.2	7.8	0.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	9.5
DUK	44.1	181.2	40.0	35.9	56.1	73.8	54.0	74.4	79.6	182.0	158.4	97.7	1,077.4
LGEE	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.3	1.3
MISO	161.8	88.9	221.3	73.6	12.3	1.8	7.2	18.3	11.6	7.0	30.4	25.3	659.4
ALTE	1.7	1.8	106.5	21.4	2.6	0.0	0.0	2.8	3.9	0.9	14.7	0.7	156.9
ALTW	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
AMIL	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CIN	34.5	0.4	75.1	39.4	7.2	1.6	0.1	0.9	0.9	3.7	9.6	5.4	178.6
CWLP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
IPL	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
MEC	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	4.8	0.0	0.9	3.7	9.4
MECS	125.6	86.8	32.9	12.8	2.6	0.2	7.1	14.6	2.0	0.5	5.3	13.0	303.5
NIPS	0.0	0.0	6.7	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	6.7
WEC	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.9	0.0	2.5	4.4
NYISO	33.1	0.0	4.4	4.9	31.7	3.0	1.5	1.1	0.4	3.0	2.4	1.1	86.5
HUDS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
LIND	3.5	0.0	0.7	1.7	3.7	0.0	0.0	0.0	0.0	0.0	0.0	0.0	9.6
NEPT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
NYIS	29.6	0.0	3.7	3.2	28.1	3.0	1.5	1.1	0.4	3.0	2.4	1.1	76.9
OVEC	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	NA	0.0
TVA	73.7	9.0	30.7	94.8	50.1	0.9	6.8	0.8	3.3	1.3	28.8	101.3	401.5
Total without Up To Congestion	402.4	374.0	429.4	350.1	283.8	177.4	193.4	266.0	162.5	269.0	361.5	336.7	3,606.1
Up To Congestion	1,726.8	1,536.7	2,627.7	3,303.5	4,530.1	4,243.5	4,448.4	5,378.3	4,196.3	4,037.7	4,339.9	3,662.8	44,031.5
Total	2,129.2	1,910.6	3,057.1	3,653.6	4,813.9	4,420.8	4,641.8	5,644.3	4,358.8	4,306.6	4,701.4	3,999.5	47,637.6

Table 9-10 Day-ahead scheduled gross export volume by interface (GWh): 2018

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
CPLE	28.3	8.4	21.1	21.3	34.3	29.5	18.1	21.5	44.7	63.7	53.4	56.3	400.6
CPLW	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DUK	53.2	0.0	1.9	0.0	0.0	7.2	0.0	1.1	72.4	29.6	5.9	21.7	193.0
LGEE	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
MISO	747.7	876.8	666.4	767.8	1,438.5	1,570.6	974.6	1,108.3	885.6	1,221.4	809.1	1,167.8	12,234.8
ALTE	246.4	387.8	61.9	83.8	421.3	399.2	268.7	294.2	162.1	245.3	97.7	149.0	2,817.4
ALTW	0.0	0.0	0.0	0.0	0.0	0.0	0.0	4.6	4.6	0.3	0.0	0.0	9.4
AMIL	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CIN	84.7	99.5	200.5	255.1	372.0	289.5	126.1	212.0	148.9	379.0	204.3	395.6	2,767.0
CWLP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
IPL	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.5	0.8	0.0	0.0	0.0	2.3
MEC	348.6	299.3	398.9	426.4	481.3	576.4	481.6	475.7	465.9	488.5	471.5	515.0	5,429.1
MECS	43.3	50.5	4.4	0.9	149.1	261.8	75.2	91.8	92.2	84.6	12.8	74.8	941.3
NIPS	0.0	1.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.2
WEC	24.6	38.6	0.9	1.6	14.8	43.7	22.9	28.5	11.2	23.8	22.9	33.5	267.1
NYISO	1,015.2	975.4	711.0	752.7	371.4	617.1	1,194.5	1,496.5	1,319.7	840.9	406.9	943.5	10,644.8
HUDS	65.3	161.1	144.4	106.8	0.8	45.0	190.5	277.5	252.5	151.3	73.6	85.5	1,554.3
LIND	22.4	27.7	28.0	14.7	7.8	0.0	0.0	0.0	0.0	0.0	0.0	0.0	100.7
NEPT	366.6	439.1	436.6	428.0	300.3	382.4	469.7	496.0	477.8	493.4	78.8	478.5	4,847.3
NYIS	560.9	347.5	102.0	203.2	62.4	189.6	534.2	723.0	589.4	196.2	254.6	379.6	4,142.6
OVEC	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	NA	0.0
TVA	38.6	5.9	7.6	6.4	12.4	77.4	53.9	78.5	106.4	364.2	190.8	62.3	1,004.3
Total without Up To Congestion	1,882.9	1,866.5	1,408.0	1,548.1	1,856.6	2,301.8	2,241.1	2,706.0	2,428.8	2,519.7	1,466.2	2,251.7	24,477.4
Up To Congestion	1,854.8	1,783.5	1,218.6	1,080.6	1,712.0	1,988.6	1,308.4	1,688.9	1,944.3	1,919.3	1,869.9	1,813.7	20,182.7
Total	3,737.7	3,650.0	2,626.7	2,628.7	3,568.6	4,290.4	3,549.6	4,394.9	4,373.1	4,439.0	3,336.1	4,065.4	44,660.1

Day-Ahead Interface Pricing Point Imports and Exports

Table 9-11 through Table 9-16 show the day-ahead scheduled interchange totals at the interface pricing points. In 2018, up to congestion transactions accounted for 92.4 percent of all scheduled import MW transactions and 45.2 percent of all scheduled export MW transactions in the Day-Ahead Energy Market. The day-ahead net scheduled interchange in 2018, including up to congestion transactions, is shown by interface pricing point in Table 9-11. Scheduled up to congestion transactions by interface pricing point in 2018 are shown in Table 9-12. Day-ahead gross scheduled imports and exports, including up to congestion transactions, are shown in Table 9-13 and Table 9-15, while gross scheduled import and export up to congestion transactions are show in Table 9-14 and Table 9-16.

On February 20, 2018, FERC issued an order limiting the eligible bidding points for up to congestion transactions to hubs, residual metered load and interfaces.[34] As a result, market participants reduced up to congestion trading effective February 22, 2018. The majority of up to congestion transaction volume is between internal buses, so while there was a significant decrease in up to congestion trading, the impact on the day-ahead net interchange was not as large. While the internal up to congestion transaction volume decreased by 54.9 percent, from 19,790.7 GWh in January to 8,921.7 GWh in December (Table 9-12), the gross import up to congestion volume increased by 112.1 percent, from 1,726.8 GWh in January to 3,662.8 GWh in December (Table 9-14) and the gross export up to congestion volume decreased by 2.2 percent, from 1,854.8 GWh in January to 1,813.7 GWh in December (Table 9-16).

There is one interface pricing point eligible for day-ahead transaction scheduling only (NIPSCO). The NIPSCO interface pricing point was created when the individual balancing authorities that integrated to form MISO still operated independently. Transactions sourcing or sinking in the NIPSCO balancing authority were eligible to receive the real-time NIPSCO interface pricing point. After the formation of the MISO RTO, all real-time transactions sourcing or sinking in NIPSCO are represented on the NERC Tag as sourcing or sinking in MISO, and thus receive the MISO interface pricing point in the Real-Time Energy Market. For this reason, it was no longer possible to receive the NIPSCO interface

34 162 FERC ¶ 61,139 (2018).

pricing point in the Real-Time Energy Market after the integration of NIPSCO into MISO.

After NIPSCO integrated into MISO on May 1, 2004, PJM kept the NIPSCO interface pricing point for the purpose of facilitating the long term day-ahead positions created at the NIPSCO Interface prior to the integration. However, the NIPSCO interface pricing point remains an eligible interface pricing point in the PJM Day-Ahead Energy Market today, and is available for all market participants to use as the pricing point for day-ahead imports, exports and wheels, INCs, DECs and up to congestion transactions. The NIPSCO interface pricing point continued to also be used as an eligible source or sink for new FTRs through the 2016/2017 planning period, but was removed as an eligible bus for the 2017/2018 planning period.

In 2018, the day-ahead net scheduled interchange at the NIPSCO interface pricing point was -5,530.8 GWh (Table 9-11). Table 9-12 shows that all -5,530.8 GWh of day-ahead net scheduled interchange submitted at the NIPSCO interface pricing point were made up of up to congestion transactions. While there is no corresponding interface pricing point available for real-time transaction scheduling, a real-time LMP is still calculated. This real-time price is used for balancing the deviations between the Day-Ahead and Real-Time Energy Markets.

PJM consolidated the Southeast and Southwest interface pricing points to a single interface pricing point with separate import and export prices (SouthIMP and SouthEXP) on October 31, 2006. At that time, the real-time Southeast and Southwest interface pricing points remained only to support certain grandfathered agreements with specific generating units and to price energy under the reserve sharing agreement with VACAR. The reserve sharing agreement allows for the transfer of energy during emergencies. Interchange transactions created as part of the reserve sharing agreement are currently settled at the Southeast interface price. PJM also kept the day-ahead Southeast and Southwest interface pricing points to facilitate long-term day-ahead positions that were entered prior to the consolidation.

Maintaining outdated definitions of interface pricing points is unnecessary, inconsistent with the tariff and creates artificial opportunities for gaming by virtual transactions and FTRs. 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 the 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. PJM should immediately eliminate interface pricing points when changes to the market mean that the pricing points can no longer be used to price actual transactions and do not reflect actual price formation.

In the Day-Ahead Energy Market, in 2018, there were net scheduled exports at nine of PJM's 19 interface pricing points eligible for day-ahead transactions.[35] The top three net exporting interface pricing points in the Day-Ahead Energy Market accounted for 67.5 percent of the total net scheduled exports: PJM/NIPSCO with 29.7 percent, PJM/NEPTUNE with 20.6 percent and PJM/NYIS with 17.2 percent of the net scheduled export volume. The four separate interface pricing points that connect PJM to the NYISO (PJM/NYIS, PJM/NEPTUNE, PJM/HUDSONTP and PJM/LINDENVFT) together represented 51.4 percent of the total net PJM scheduled exports in the Day-Ahead Energy Market. However, the PJM/LINDENVFT interface pricing point had net scheduled imports in the Day-Ahead Energy Market.

In the Day-Ahead Energy Market, in 2018, there were net scheduled imports at ten of PJM's 19 interface pricing points eligible for day-ahead transactions. The top three net importing interface pricing points in the Day-Ahead Energy Market accounted for 82.7 percent of the total net scheduled imports: PJM/OVEC with 41.9 percent, PJM/SouthIMP with 23.4 percent and PJM/NORTHWEST with 17.4 percent of the net import volume. The four separate interface pricing points that connect PJM to the NYISO (PJM/NYIS, PJM/NEPTUNE, PJM/HUDSONTP and PJM/LINDENVFT) together represented 2.2 percent of the total net PJM scheduled imports in the Day-Ahead Energy Market. However, the PJM/NYIS, PJM/NEPTUNE and PJM/LINDENVFT interface pricing points had net scheduled exports in the Day-Ahead Energy Market.

In the Day-Ahead Energy Market, in 2018, up to congestion transactions had net scheduled exports at four of PJM's 19 interface pricing points eligible for

35 In December 2018, PJM integrated OVEC, reducing the number of day-ahead interface pricing points to 18.

day-ahead transactions.[36] The top two net exporting interface pricing points eligible for up to congestion transactions accounted for 87.5 percent of the total net up to congestion scheduled exports: PJM/NIPSCO with 65.9 percent and PJM/SouthEXP with 21.6 percent of the net up to congestion scheduled export volume. The four separate interface pricing points that connect PJM to the NYISO (PJM/NYIS, PJM/NEPTUNE, PJM/HUDSONTP and PJM/LINDENVFT) together represented 11.4 percent of the total net scheduled up to congestion exports in the Day-Ahead Energy Market. However, the PJM/NYIS, PJM/NEPTUNE and PJM/LINDENVFT interface pricing points had net up to congestion scheduled imports in the Day-Ahead Energy Market.

In the Day-Ahead Energy Market, in 2018, up to congestion transactions had net scheduled imports at nine of PJM's 19 interface pricing points eligible for day-ahead transactions. The top three net importing interface pricing points eligible for up to congestion transactions accounted for 76.8 percent of the total net up to congestion scheduled imports: PJM/Northwest with 28.2 percent, PJM/OVEC with 28.0 percent and PJM/MISO with 20.6 percent of the net import up to congestion volume. The four separate interface pricing points that connect PJM to the NYISO (PJM/NYIS, PJM/NEPTUNE, PJM/HUDSONTP and PJM/LINDENVFT) together represented 7.5 percent of the total net scheduled up to congestion imports in the Day-Ahead Energy Market. However, the PJM/HUDSONTP interface pricing points had net up to congestion scheduled exports in the Day-Ahead Energy Market.[37]

Table 9-11 Day-ahead scheduled net interchange volume by interface pricing point (GWh): 2018

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
IMO	84.8	49.1	(132.9)	(21.7)	5.0	93.3	154.5	146.4	75.5	84.6	69.1	155.9	763.6
MISO	(119.2)	(472.3)	433.0	397.0	(522.3)	(426.1)	212.1	416.7	368.9	(341.7)	71.9	14.6	32.7
NIPSCO	(432.4)	(707.6)	(287.3)	(137.6)	(606.9)	(897.8)	(349.9)	(353.7)	(939.9)	(447.0)	(94.0)	(276.7)	(5,530.8)
NORTHWEST	(300.3)	(121.6)	368.6	115.2	590.0	511.4	818.1	1,168.5	421.7	(258.6)	(54.6)	504.8	3,763.3
NYISO	(937.3)	(970.5)	(787.0)	(753.8)	(238.4)	(497.6)	(985.5)	(1,191.3)	(1,146.6)	(359.9)	(405.2)	(827.8)	(9,100.9)
HUDSONTP	(81.6)	(188.0)	(282.8)	(287.8)	(127.3)	(62.1)	(241.9)	(265.1)	(332.8)	(238.1)	(180.6)	(243.8)	(2,531.9)
LINDENVFT	1.7	(30.0)	(20.8)	(19.6)	83.5	(11.9)	66.9	131.6	84.7	9.0	107.8	63.2	466.0
NEPTUNE	(343.9)	(421.9)	(462.5)	(392.2)	(249.0)	(322.2)	(389.7)	(369.2)	(393.9)	(53.0)	(126.0)	(317.3)	(3,840.8)
NYIS	(513.5)	(330.6)	(20.8)	(54.2)	54.3	(101.3)	(420.7)	(688.6)	(504.6)	(77.9)	(206.4)	(329.9)	(3,194.2)
OVEC	(143.2)	103.4	408.5	822.7	913.5	814.4	1,037.8	976.1	1,194.2	1,281.5	1,630.0	NA	9,038.8
Southern Imports	835.6	737.6	498.8	690.9	1,206.7	808.0	460.4	440.2	433.4	582.6	558.7	756.4	8,009.3
CPLEIMP	1.1	5.2	0.0	12.9	3.6	4.3	1.2	73.6	26.2	15.9	64.3	1.7	210.1
DUKIMP	3.8	2.7	33.7	29.8	24.2	3.2	7.2	26.4	26.7	95.2	79.0	27.9	359.8
NCMPAIMP	118.7	164.6	120.2	126.0	139.8	124.4	126.1	120.7	82.5	133.2	108.9	143.2	1,508.2
SOUTHEAST	270.0	162.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.8	434.2
SOUTHWEST	253.8	198.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	451.9
SOUTHIMP	188.3	204.6	344.9	522.1	1,039.1	676.1	326.0	219.4	298.0	338.2	306.5	581.7	5,045.0
Southern Exports	(596.5)	(357.6)	(71.3)	(87.9)	(102.2)	(275.4)	(255.3)	(353.5)	(421.5)	(673.7)	(410.6)	(393.1)	(3,998.6)
CPLEEXP	(27.8)	(8.0)	(20.6)	(20.3)	(32.2)	(24.1)	(17.6)	(21.7)	(43.0)	(54.4)	(50.1)	(53.4)	(373.4)
DUKEXP	(0.4)	0.0	(1.0)	0.0	0.0	(9.1)	0.0	0.0	(16.9)	(1.9)	0.0	(19.2)	(48.5)
NCMPAEXP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	(5.3)	0.0	0.0	(5.3)
SOUTHEAST	(24.3)	(16.6)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	(40.9)
SOUTHWEST	(308.5)	(239.5)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	(548.0)
SOUTHEXP	(235.4)	(93.4)	(49.7)	(67.6)	(70.0)	(242.2)	(237.7)	(331.7)	(361.5)	(612.2)	(360.5)	(320.5)	(2,982.5)
Total	(1,608.5)	(1,739.4)	430.5	1,024.9	1,245.3	130.4	1,092.2	1,249.4	(14.3)	(132.4)	1,365.3	(65.9)	2,977.4

36 In December 2018, PJM integrated OVEC, reducing the number of day-ahead interface pricing points to 18.

37 In the Day-Ahead Energy Market, six PJM interface pricing points (PJM/CPLEIMP, PJM/DUKIMP, PJM/NCMPAIMP, PJM/CPLEEXP, PJM/DUKEXP and PJM/NCMPAEXP) had up to congestion net interchange of zero.

Table 9-12 Up to congestion scheduled net interchange volume by interface pricing point (GWh): 2018

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
IMO	(43.7)	(37.7)	(207.2)	(34.3)	2.6	93.1	147.9	134.5	76.6	84.0	63.9	142.8	422.4
MISO	246.7	101.9	586.9	683.4	424.4	568.9	713.5	1,045.1	779.1	400.8	388.6	687.9	6,627.2
NIPSCO	(432.4)	(707.6)	(287.3)	(137.6)	(606.9)	(897.8)	(349.9)	(353.7)	(939.9)	(447.0)	(94.0)	(276.7)	(5,530.8)
NORTHWEST	48.3	177.7	742.0	541.7	1,070.1	1,085.5	1,290.7	1,641.9	880.4	223.0	412.7	987.7	9,101.8
NYISO	44.8	6.1	(80.5)	(5.9)	103.9	116.6	207.6	303.0	176.7	470.2	(0.7)	115.7	1,457.3
HUDSONTP	(16.3)	(26.8)	(138.4)	(181.0)	(126.4)	(17.1)	(51.4)	21.5	(66.7)	(86.7)	(107.0)	(158.4)	(954.9)
LINDENVFT	20.6	(2.3)	6.5	(6.6)	87.6	(11.9)	66.9	131.6	84.7	9.0	107.8	63.2	557.1
NEPTUNE	22.8	17.1	(25.9)	35.8	51.3	60.2	80.0	125.6	83.9	440.4	(47.3)	161.2	1,005.3
NYIS	17.8	18.1	77.4	145.8	91.4	85.4	112.1	24.2	74.9	107.5	45.8	49.7	849.9
OVEC	(143.2)	103.4	408.5	822.7	913.5	814.4	1,037.8	976.1	1,194.2	1,281.5	1,630.0	NA	9,038.8
Southern Imports	628.1	452.6	287.4	413.3	966.0	635.4	275.7	194.8	282.8	321.7	230.0	444.4	5,132.2
CPLEIMP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DUKIMP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
NCMPAIMP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHEAST	270.0	162.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	432.4
SOUTHWEST	253.8	198.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	451.9
SOUTHIMP	104.3	92.1	287.4	413.3	966.0	635.4	275.7	194.8	282.8	321.7	230.0	444.4	4,247.9
Southern Exports	(476.5)	(343.3)	(40.7)	(60.3)	(55.5)	(161.3)	(183.3)	(252.3)	(198.0)	(215.7)	(160.5)	(252.8)	(2,400.1)
CPLEEXP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DUKEXP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
NCMPAEXP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHEAST	(24.3)	(16.6)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	(40.9)
SOUTHWEST	(308.5)	(239.5)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	(548.0)
SOUTHEXP	(143.7)	(87.2)	(40.7)	(60.3)	(55.5)	(161.3)	(183.3)	(252.3)	(198.0)	(215.7)	(160.5)	(252.8)	(1,811.1)
Total Interfaces	(128.0)	(246.8)	1,409.1	2,222.9	2,818.1	2,254.8	3,140.0	3,689.3	2,252.0	2,118.4	2,470.0	1,849.1	23,848.8
INTERNAL	19,790.7	14,068.6	3,232.1	4,557.9	5,997.0	5,500.9	7,588.9	6,999.4	6,322.5	6,823.3	7,451.0	8,921.7	97,254.0
Total	19,662.7	13,821.8	4,641.3	6,780.8	8,815.1	7,755.8	10,728.9	10,688.7	8,574.5	8,941.6	9,921.0	10,770.8	121,102.8

Table 9-13 Day-ahead scheduled gross import volume by interface pricing point (GWh): 2018

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
IMO	165.1	100.3	92.7	48.2	51.6	129.0	182.7	198.3	108.8	120.0	101.5	201.9	1,500.0
MISO	373.7	241.8	782.6	800.4	646.4	760.6	826.0	1,209.7	910.6	619.4	658.1	997.3	8,826.4
NIPSCO	33.5	8.7	92.2	99.5	129.8	116.3	112.2	180.8	54.7	131.0	248.1	204.8	1,411.5
NORTHWEST	239.6	335.4	799.6	697.8	1,236.7	1,292.7	1,463.9	1,855.2	1,153.3	668.2	905.0	1,286.8	11,934.2
NYISO	236.8	202.0	302.9	409.4	357.8	286.7	432.8	539.6	406.1	827.2	451.1	552.4	5,004.6
HUDSONTP	35.6	64.7	79.6	59.8	28.5	42.5	29.0	45.4	27.4	23.5	24.5	25.8	486.4
LINDENVFT	67.0	35.4	68.9	87.5	111.8	56.5	110.2	148.6	114.1	136.8	137.8	90.4	1,165.1
NEPTUNE	30.2	27.1	39.5	78.0	76.1	82.9	122.7	148.8	113.7	465.3	96.1	214.7	1,495.1
NYIS	104.0	74.7	114.8	184.1	141.4	104.7	170.8	196.8	150.9	201.6	192.6	221.5	1,858.0
OVEC	245.1	284.8	488.4	907.3	1,184.8	1,027.6	1,163.8	1,220.6	1,291.9	1,358.3	1,778.9	NA	10,951.6
Southern Imports	835.6	737.6	498.8	690.9	1,206.7	808.0	460.4	440.2	433.4	582.6	558.7	756.4	8,009.3
CPLEIMP	1.1	5.2	0.0	12.9	3.6	4.3	1.2	73.6	26.2	15.9	64.3	1.7	210.1
DUKIMP	3.8	2.7	33.7	29.8	24.2	3.2	7.2	26.4	26.7	95.2	79.0	27.9	359.8
NCMPAIMP	118.7	164.6	120.2	126.0	139.8	124.4	126.1	120.7	82.5	133.2	108.9	143.2	1,508.2
SOUTHEAST	270.0	162.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.8	434.2
SOUTHWEST	253.8	198.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	451.9
SOUTHIMP	188.3	204.6	344.9	522.1	1,039.1	676.1	326.0	219.4	298.0	338.2	306.5	581.7	5,045.0
Southern Exports	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CPLEEXP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DUKEXP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
NCMPAEXP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHEAST	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHWEST	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHEXP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total	2,129.2	1,910.6	3,057.1	3,653.6	4,813.9	4,420.8	4,641.8	5,644.3	4,358.8	4,306.6	4,701.4	3,999.5	47,637.6

Table 9-14 Up to congestion scheduled gross import volume by interface pricing point (GWh): 2018

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
IMO	36.5	13.5	18.3	35.5	49.2	128.8	175.6	183.6	106.7	119.4	96.3	188.9	1,152.2
MISO	340.5	239.6	643.3	745.5	637.5	759.0	825.9	1,206.0	901.0	614.9	632.9	986.6	8,532.7
NIPSCO	33.5	8.7	92.2	99.5	129.8	116.3	112.2	180.8	54.7	131.0	248.1	204.8	1,411.5
NORTHWEST	239.6	335.4	799.6	697.8	1,236.7	1,292.7	1,463.9	1,855.2	1,153.3	668.2	905.0	1,286.8	11,934.2
NYISO	203.7	202.0	298.5	404.5	326.1	283.7	431.3	537.2	405.8	824.2	448.7	551.3	4,917.0
HUDSONTP	35.6	64.7	79.6	59.8	28.5	42.5	29.0	45.4	27.4	23.5	24.5	25.8	486.4
LINDENVFT	63.5	35.4	68.3	85.7	108.2	56.5	110.2	148.6	114.1	136.8	137.8	90.4	1,155.5
NEPTUNE	30.2	27.1	39.5	78.0	76.1	82.9	122.7	147.6	113.7	465.3	96.1	214.7	1,493.9
NYIS	74.4	74.7	111.1	180.9	113.3	101.7	169.4	195.7	150.6	198.6	190.2	220.4	1,781.1
OVEC	245.1	284.8	488.4	907.3	1,184.8	1,027.6	1,163.8	1,220.6	1,291.9	1,358.3	1,778.9	NA	10,951.6
Southern Imports	628.1	452.6	287.4	413.3	966.0	635.4	275.7	194.8	282.8	321.7	230.0	444.4	5,132.2
CPLEIMP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DUKIMP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
NCMPAIMP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHEAST	270.0	162.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	432.4
SOUTHWEST	253.8	198.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	451.9
SOUTHIMP	104.3	92.1	287.4	413.3	966.0	635.4	275.7	194.8	282.8	321.7	230.0	444.4	4,247.9
Southern Exports	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CPLEEXP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DUKEXP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
NCMPAEXP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHEAST	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHWEST	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHEXP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total Interfaces	1,726.8	1,536.7	2,627.7	3,303.5	4,530.1	4,243.5	4,448.4	5,378.3	4,196.3	4,037.7	4,339.9	3,662.8	44,031.5

Table 9-15 Day-ahead scheduled gross export volume by interface pricing point (GWh): 2018

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
IMO	80.3	51.2	225.6	69.9	46.7	35.6	28.2	51.9	33.3	35.4	32.4	46.0	736.4
MISO	492.9	714.1	349.5	403.4	1,168.7	1,186.6	613.8	793.0	541.7	961.1	586.2	982.7	8,793.7
NIPSCO	465.8	716.3	379.5	237.2	736.7	1,014.1	462.2	534.5	994.6	578.0	342.0	481.4	6,942.3
NORTHWEST	539.8	457.0	431.0	582.6	646.7	781.3	645.7	686.8	731.6	926.8	959.6	782.0	8,170.9
NYISO	1,174.1	1,172.5	1,089.9	1,163.1	596.3	784.2	1,418.2	1,730.8	1,552.8	1,187.1	856.3	1,380.2	14,105.6
HUDSONTP	117.2	252.7	362.5	347.6	155.8	104.7	270.9	310.5	360.2	261.5	205.1	269.6	3,018.3
LINDENVFT	65.3	65.5	89.8	107.0	28.3	68.4	43.4	17.0	29.4	127.8	30.0	27.2	699.1
NEPTUNE	374.0	449.1	502.0	470.2	325.1	405.1	512.4	518.0	507.6	518.3	222.2	532.0	5,336.0
NYIS	617.5	405.3	135.7	238.3	87.1	206.0	591.5	885.4	655.5	279.5	399.0	551.4	5,052.2
OVEC	388.3	181.4	79.9	84.6	271.3	213.2	126.0	244.5	97.7	76.9	149.0	NA	1,912.7
Southern Imports	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CPLEIMP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DUKIMP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
NCMPAIMP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHEAST	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHWEST	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHIMP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Southern Exports	596.5	357.6	71.3	87.9	102.2	275.4	255.3	353.5	421.5	673.7	410.6	393.1	3,998.6
CPLEEXP	27.8	8.0	20.6	20.3	32.2	24.1	17.6	21.7	43.0	54.4	50.1	53.4	373.4
DUKEXP	0.4	0.0	1.0	0.0	0.0	9.1	0.0	0.0	16.9	1.9	0.0	19.2	48.5
NCMPAEXP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	5.3	0.0	0.0	5.3
SOUTHEAST	24.3	16.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	40.9
SOUTHWEST	308.5	239.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	548.0
SOUTHEXP	235.4	93.4	49.7	67.6	70.0	242.2	237.7	331.7	361.5	612.2	360.5	320.5	2,982.5
Total	3,737.7	3,650.0	2,626.7	2,628.7	3,568.6	4,290.4	3,549.6	4,394.9	4,373.1	4,439.0	3,336.1	4,065.4	44,660.1

Table 9-16 Up to congestion scheduled gross export volume by interface pricing point (GWh): 2018

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
IMO	80.3	51.2	225.6	69.9	46.7	35.6	27.7	49.2	30.1	35.4	32.4	46.0	729.9
MISO	93.8	137.8	56.5	62.1	213.0	190.1	112.4	160.9	121.9	214.1	244.3	298.7	1,905.6
NIPSCO	465.8	716.3	379.5	237.2	736.7	1,014.1	462.2	534.5	994.6	578.0	342.0	481.4	6,942.3
NORTHWEST	191.3	157.7	57.6	156.2	166.6	207.2	173.1	213.3	272.9	445.2	492.3	299.1	2,832.5
NYISO	158.9	195.9	378.9	410.4	222.2	167.1	223.8	234.3	229.0	354.0	449.4	435.6	3,459.6
HUDSONTP	51.9	91.5	218.1	240.8	155.0	59.6	80.4	23.9	94.1	110.2	131.6	184.2	1,441.4
LINDENVFT	42.9	37.8	61.7	92.3	20.5	68.4	43.4	17.0	29.4	127.8	30.0	27.2	598.4
NEPTUNE	7.4	10.0	65.4	42.2	24.8	22.7	42.7	22.0	29.7	24.9	143.4	53.5	488.7
NYIS	56.7	56.6	33.7	35.1	22.0	16.4	57.3	171.5	75.7	91.1	144.5	170.7	931.2
OVEC	388.3	181.4	79.9	84.6	271.3	213.2	126.0	244.5	97.7	76.9	149.0	NA	1,912.7
Southern Imports	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CPLEIMP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DUKIMP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
NCMPAIMP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHEAST	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHWEST	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHIMP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Southern Exports	476.5	343.3	40.7	60.3	55.5	161.3	183.3	252.3	198.0	215.7	160.5	252.8	2,400.1
CPLEEXP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DUKEXP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
NCMPAEXP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHEAST	24.3	16.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	40.9
SOUTHWEST	308.5	239.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	548.0
SOUTHEXP	143.7	87.2	40.7	60.3	55.5	161.3	183.3	252.3	198.0	215.7	160.5	252.8	1,811.1
Total Interfaces	1,854.8	1,783.5	1,218.6	1,080.6	1,712.0	1,988.6	1,308.4	1,688.9	1,944.3	1,919.3	1,869.9	1,813.7	20,182.7

Table 9-17 Active scheduling interfaces: 2018[38]

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
ALTE	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
ALTW	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
AMIL	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
CIN	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
CPLE	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
CPLW	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
CWLP	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
DUK	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
HUDS	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
IPL	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
LGEE	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
LIND	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
MEC	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
MECS	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
NEPT	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
NIPS	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
NYIS	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
OVEC	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	
TVA	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
WEC	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active

38 On July 2, 2012, Duke Energy Corp. (DUK) completed a merger with Progress Energy Inc. (CPLE and CPLW). As of December 31, 2018, DUK, CPLE and CPLW continued to operate as separate balancing authorities, and are still defined as distinct interfaces in the PJM energy market.

Figure 9-3 PJM's footprint and its external scheduling interfaces

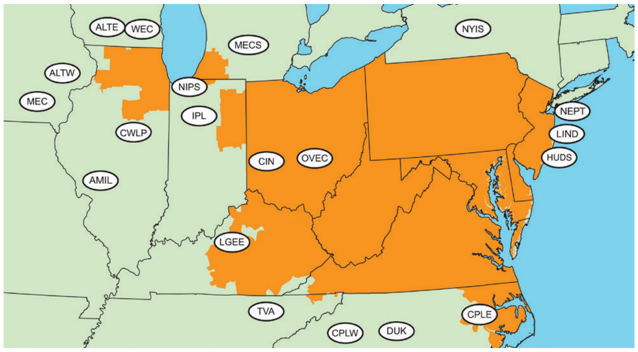


Table 9-18 Active scheduled interface pricing points: 2018[39]

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
CPLEEXP	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
CPLEIMP	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
DUKEXP	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
DUKIMP	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
HUDSONTP	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
LINDENVFT	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
MISO	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
NCMPAEXP	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
NCMPAIMP	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
NEPTUNE	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
NIPSCO	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
Northwest	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
NYIS	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
Ontario IESO	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
OVEC	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	
Southeast	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
SOUTHEXP	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
SOUTHIMP	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
Southwest	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active

Loop Flows

Actual energy flows are the real-time metered power flows at an interface for a defined period. The comparable scheduled flows are the real-time power flows scheduled at an interface for a defined period. Inadvertent interchange is the difference between the total actual flows for the PJM system (net actual interchange) and the total scheduled flows for the PJM system (net scheduled interchange) for a defined period. Loop flows are the difference between actual and scheduled power flows at a specific interface. Loop flows can exist at the same time that inadvertent interchange is zero. For example, actual imports could exceed scheduled imports at one interface and actual exports could exceed scheduled exports at another interface by the same amount. The result is loop flow, despite the fact that system actual and scheduled power flow net to a zero difference.[40]

Loop flows result, in part, from a mismatch between incentives to use a particular scheduled transmission path and the market-based price differentials at interface pricing points that result from the actual physical flows on the transmission system.

PJM's approach to interface pricing attempts to match prices with physical power flows and their impacts on the transmission system. For example, if market participants want to import energy from the Southwest Power Pool (SPP) to PJM, they are likely to choose a scheduled path with the fewest transmission providers along the path and therefore the lowest transmission costs for the transaction, regardless of whether the resultant path is related to the physical flow of power. The lowest cost transmission path runs from SPP, through MISO, and into PJM, requiring only three transmission reservations, two of which are available at no cost (MISO transmission would be free based on the regional through and out rates, and the PJM transmission would be free, if using spot import transmission). Any other transmission path entering PJM, where the generating control area is to the south, would require the market participant to acquire transmission through nonmarket balancing authorities, and thus incur additional transmission costs. PJM's interface pricing method recognizes that transactions sourcing in SPP and sinking in PJM will create flows across the southern border and prices those transactions at the SouthIMP interface price. As a result, the transaction is priced appropriately, but a difference between scheduled and actual flows is created at PJM's borders. For example, if a 100 MW transaction

39 The NIPSCO interface pricing point is valid only in the Day-Ahead Energy Market.

40 See the *2012 State of the Market Report for PJM*, Volume 2, Section 8, "Interchange Transactions," for a more detailed discussion.

were submitted, there would be 100 MW of scheduled flow at the PJM/MISO interface border, but there would be no actual flows on the interface. Correspondingly, there would be no scheduled flows at the PJM/Southern interface border, but there would be 100 MW of actual flows on the interface. In 2018, there were net scheduled flows of 4,815 GWh through MISO that received an interface pricing point associated with the southern interface but there were no net scheduled flows across the southern interface that received the MISO interface pricing point.

In 2018, net scheduled interchange was -19,010 GWh and net actual interchange was -18,351 GWh, a difference of 659 GWh. In 2017, net scheduled interchange was -22,958 GWh and net actual interchange was -23,147 GWh, a difference of 189 GWh. This difference is inadvertent interchange. PJM attempts to minimize the amount of accumulated inadvertent interchange by continually monitoring and correcting for inadvertent interchange. PJM can reduce the accumulation of inadvertent interchange using unilateral or bilateral paybacks.[41]

Table 9-19 shows that in 2018, the Northern Indiana Public Service (NIPS) Interface had the largest loop flows of any interface with 3 GWh of net scheduled interchange and -8,681 GWh of net actual interchange, a difference of 8,684 GWh.

41 See PJM. "Manual 12: Balancing Operations," Rev. 38 (April 20, 2018).

Table 9-19 Net scheduled and actual PJM flows by interface (GWh): 2018

	Actual	Net Scheduled	Difference (GWh)
CPLE	3,643	459	3,184
CPLW	(1,011)	5	(1,015)
DUK	1,652	772	880
LGEE	4,695	1,657	3,037
MISO	(25,547)	(9,559)	(15,988)
ALTE	(3,634)	(2,796)	(838)
ALTW	(1,916)	(10)	(1,906)
AMIL	(325)	3,046	(3,371)
CIN	(5,762)	(4,993)	(769)
CWLP	(34)	0	(34)
IPL	269	(689)	958
MEC	(4,681)	(4,960)	278
MECS	(7,859)	689	(8,548)
NIPS	(8,681)	3	(8,684)
WEC	7,076	150	6,926
NYISO	(12,043)	(11,968)	(74)
HUDS	(1,993)	(1,993)	0
LIND	(1,761)	(1,761)	0
NEPT	(4,837)	(4,837)	0
NYIS	(3,451)	(3,377)	(74)
OVEC	3,193	(160)	3,353
TVA	7,066	(216)	7,282
Total	(18,351)	(19,010)	659

Every external balancing authority is mapped to an import and export interface pricing point. The mapping is designed to reflect the physical flow of energy between PJM and each balancing authority. The net scheduled values for interface pricing points are defined as the MWh of scheduled transactions that will receive the interface pricing point based on the external balancing authority mapping.[42] For example, the MWh for a transaction whose transmission path is SPP through MISO and into PJM would be reflected in the SouthIMP interface pricing point net schedule totals because SPP is mapped to the SouthIMP interface pricing point. The actual flow on an interface pricing point is defined as the metered flow across the transmission lines that are included in the interface pricing point.

The differences between the scheduled MWh mapped to a specific interface pricing point and actual power flows at the interface pricing points provide a better measure of loop flows than differences at the interfaces. The scheduled transactions are mapped to interface pricing points based on the expected flow from the generation balancing authority and load balancing authority, whereas scheduled transactions are assigned

42 The terms balancing authority and control area are used interchangeably in this section. The NERC Tag applications maintained the terminology of generation control area (GCA) and load control area (LCA) after the implementation of the NERC functional model. The NERC functional model classifies the balancing authority as a reliability service function, with, among other things, the responsibility for balancing generation, demand and interchange balance.

to interfaces based solely on the OASIS path that the market participants reflect the transmission path into or out of PJM to one neighboring balancing authority. Power flows at the interface pricing points provide a more accurate reflection of where scheduled power flows actually enter or leave the PJM footprint based on the complete transaction path.

Table 9-20 shows the net scheduled and actual PJM flows by interface pricing point. The CPLEEXP, CPLEIMP, DUKEXP, DUKIMP, NCMPAEXP, and NCMPAIMP interface pricing points were created as part of operating agreements with external balancing authorities, and reflect the same physical ties as the SouthIMP and SouthEXP interface pricing points.

Because the SouthIMP and SouthEXP interface pricing points are the same physical point, if there are net actual exports from the PJM footprint to the southern region, by definition, there cannot be net actual imports into the PJM footprint from the southern region and therefore there will not be actual flows at the SouthIMP interface pricing point. In the case of PJM's southern border, loop flows can be analyzed by comparing the net scheduled and net actual flows as a sum of the pricing points, rather than the individual pricing points. To accurately calculate the loop flows from the southern region, the net actual flows from the southern region are compared to the net scheduled flows from the southern region. The net actual flows from the southern region are determined by summing the total southern import actual flows (29,635 GWh) and the total southern export actual flows (-13,589 GWh) for 16,046 GWh of net imports. The net scheduled flows from the southern region are determined by summing the total southern import scheduled flows (11,734 GWh) and the total southern export scheduled flows (-4,241 GWh) for 7,492 GWh of net imports. In 2018, the loop flows at the southern region were the difference between the southern region net scheduled flows (7,492 GW) and the southern region net actual flows (16,046 GWh) for a total of 8,553 GWh of loop flows.

The IMO interface pricing point with the Ontario IESO was created to reflect the fact that transactions that originate or sink in the Ontario Independent Electricity System Operator (IMO) balancing authority create physical flows that are split between the MISO and NYISO interface pricing points depending on transmission system conditions, so a mapping to a single interface pricing point does not reflect the actual flows. PJM created the IMO interface pricing point to reflect the actual power flows across both the MISO/PJM and NYISO/PJM interfaces. The IMO does not have physical ties with PJM because it is not contiguous. Table 9-20 shows actual flows associated with the IMO interface pricing point as zero because there is no PJM/IMO Interface. The actual flows between IMO and PJM are included in the actual flows at the MISO and NYISO interface pricing points.

Table 9-20 PJM flows by interface pricing point (GWh): 2018

	Actual	Net Scheduled	Difference (GWh)
IMO	0	1,532	(1,532)
MISO	(25,547)	(15,902)	(9,645)
NORTHWEST	0	(3)	3
NYISO	(12,043)	(11,970)	(73)
HUDSONTP	(1,993)	(1,993)	(0)
LINDENVFT	(1,761)	(1,761)	0
NEPTUNE	(4,837)	(4,837)	0
NYIS	(3,451)	(3,379)	(73)
OVEC	3,193	(160)	3,353
Southern Imports	29,635	11,734	17,901
CPLEIMP	0	3	(3)
DUKIMP	0	303	(303)
NCMPAIMP	0	1,112	(1,112)
SOUTHEAST	0	0	0
SOUTHWEST	0	0	0
SOUTHIMP	29,635	10,316	19,319
Southern Exports	(13,589)	(4,241)	(9,348)
CPLEEXP	0	(236)	236
DUKEXP	0	(696)	696
NCMPAEXP	0	(0)	0
SOUTHEAST	0	(1)	1
SOUTHWEST	0	0	0
SOUTHEXP	(13,589)	(3,309)	(10,280)
Total	(18,351)	(19,010)	659

Table 9-21 shows the net scheduled and actual PJM flows by interface pricing point, with adjustments made to the MISO and NYISO scheduled interface pricing points based on the quantities of scheduled interchange where transactions from the IMO entered the PJM energy market. For example, Table 9-23 shows that 1,534 of the 1,536 GWh (99.9 percent) of gross scheduled transactions that were mapped to the IMO interface pricing point were scheduled as imports through MISO, and 1 of the 1,536 GWh (0.1 percent) were scheduled as imports through the NYISO.

Table 9-21 shows that in 2018, the SouthIMP interface pricing point had the largest loop flows of any interface pricing point with 10,316 GWh of net scheduled interchange and 29,635 GWh of net actual interchange, a difference of 19,319 GWh.

Table 9-21 PJM flows by interface pricing point (GWh) (Adjusted for IMO Scheduled Interfaces): 2018

	Actual	Net Scheduled	Difference (GWh)
MISO	(25,547)	(14,371)	(11,176)
NORTHWEST	0	(3)	3
NYISO	(12,043)	(11,968)	(74)
HUDSONTP	(1,993)	(1,993)	(0)
LINDENVFT	(1,761)	(1,761)	0
NEPTUNE	(4,837)	(4,837)	0
NYIS	(3,451)	(3,377)	(74)
OVEC	3,193	(160)	3,353
Southern Imports	29,635	11,734	17,901
CPLEIMP	0	3	(3)
DUKIMP	0	303	(303)
NCMPAIMP	0	1,112	(1,112)
SOUTHEAST	0	0	0
SOUTHWEST	0	0	0
SOUTHIMP	29,635	10,316	19,319
Southern Exports	(13,589)	(4,241)	(9,348)
CPLEEXP	0	(236)	236
DUKEXP	0	(696)	696
NCMPAEXP	0	(0)	0
SOUTHEAST	0	(1)	1
SOUTHWEST	0	0	0
SOUTHEXP	(13,589)	(3,309)	(10,280)
Total	(18,351)	(19,010)	659

PJM attempts to ensure that external energy transactions are priced appropriately through the assignment of interface prices based on the expected actual flow from the generation balancing authority (source) and load balancing authority (sink) as specified on the NERC Tag. Assigning prices in this manner is a reasonable approach to ensuring that transactions receive or pay the PJM market value of the transaction based on expected flows, but this method does not address loop flow issues.

Loop flows remain a significant concern for the efficiency of the PJM market. Loop flows can have negative impacts on the efficiency of markets with explicit locational pricing, including impacts on locational prices, on FTR revenue adequacy and on system operations, and can be evidence of attempts to game the markets.

The MMU recommends that PJM implement a validation method for submitted transactions that would prohibit market participants from breaking transactions into smaller segments to defeat the interface pricing rule and receive higher prices (for imports) or lower prices (for exports) from PJM resulting from the inability to identify the true source or sink of the transaction. If all of the Northeast ISOs and RTOs implemented validation to prohibit the breaking of transactions into smaller segments, the level of Lake Erie loop flow would be reduced.

The MMU also recommends that PJM implement a validation method for submitted transactions that would require market participants to submit transactions on paths that reflect the expected actual power flow in order to reduce unscheduled loop flows.

Table 9-22 shows the net scheduled and actual PJM flows by interface and interface pricing point. This table shows the interface pricing points that were assigned to energy transactions that had paths at each of PJM's interfaces. For example, Table 9-22 shows that in 2018, the majority of imports to the PJM energy market for which a market participant specified Cinergy as the interface with PJM based on the scheduled transmission path, had a generation control area mapped to the SOUTHIMP Interface, and thus actual flows were assigned the SOUTHIMP interface pricing point (390 GWh). The majority of exports from the PJM energy market for which a market participant specified Cinergy as the interface with PJM based on the scheduled transmission path had a load control area for which the actual flows would leave the PJM energy market at the MISO Interface, and were assigned the MISO interface pricing point (-5,389 GWh).

Table 9-22 Net scheduled and actual flows by interface and interface pricing point (GWh): 2018

Interface	Interface Pricing Point	Actual	Net Scheduled	Difference (GWh)	Interface Pricing Point	Interface	Actual	Net Scheduled	Difference (GWh)
ALTE		(3,634)	(2,796)	(838)	IPL		269	(689)	958
	IMO	0	490	(490)		IMO	0	50	(50)
	MISO	(3,634)	(3,456)	(178)		MISO	269	(784)	1,053
	SOUTHEXP	0	(1)	1		SOUTHEXP	0	(0)	0
	SOUTHIMP	0	171	(171)		SOUTHIMP	0	45	(45)
ALTW		(1,916)	(10)	(1,906)	LGEE		4,695	1,657	3,037
	IMO	0	1	(1)		SOUTHEXP	(6,546)	(147)	(6,399)
	MISO	(1,916)	(11)	(1,904)		SOUTHIMP	11,240	1,804	9,436
	SOUTHIMP	0	1	(1)	LIND		(1,761)	(1,761)	0
AMIL		(325)	3,046	(3,371)		LINDENVFT	(1,761)	(1,761)	0
	MISO	(325)	(4)	(320)	MEC		(4,681)	(4,960)	278
	SOUTHIMP	0	3,051	(3,051)		IMO	0	1	(1)
CIN		(5,762)	(4,993)	(769)		MISO	(4,681)	(4,976)	295
	IMO	0	25	(25)		SOUTHEXP	0	(0)	0
	MISO	(5,762)	(5,389)	(372)		SOUTHIMP	0	16	(16)
	NORTHWEST	0	(3)	3	MECS		(7,859)	689	(8,548)
	SOUTHEXP	0	(15)	15		IMO	0	967	(967)
	SOUTHIMP	0	390	(390)		MISO	(7,859)	(1,022)	(6,837)
CPLE		3,643	459	3,184		SOUTHEXP	0	(0)	0
	CPLEEXP	0	(236)	236		SOUTHIMP	0	744	(744)
	CPLEIMP	0	3	(3)	NEPT		(4,837)	(4,837)	0
	DUKEXP	0	(20)	20		NEPTUNE	(4,837)	(4,837)	0
	DUKIMP	0	127	(127)	NIPS		(8,681)	3	(8,684)
	NCMPAIMP	0	621	(621)		IMO	0	(2)	2
	SOUTHEXP	(1,887)	(584)	(1,303)		MISO	(8,681)	4	(8,685)
	SOUTHIMP	5,530	549	4,981		SOUTHIMP	0	0	(0)
	SOUTHEAST	0	(1)	1	NYIS		(3,451)	(3,377)	(74)
CPLW		(1,011)	5	(1,015)		IMO	0	1	(1)
	DUKIMP	0	2	(2)		NYIS	(3,451)	(3,379)	(73)
	NCMPAIMP	0	3	(3)	OVEC		3,193	(160)	3,353
	SOUTHEXP	(1,120)	(6)	(1,114)		OVEC	3,193	(160)	3,353
	SOUTHIMP	109	6	103	TVA		7,066	(216)	7,282
CWLP		(34)	0	(34)		DUKEXP	0	(2)	2
	MISO	(34)	0	(34)		MISO	0	0	0
DUK		1,652	772	880		SOUTHEXP	(3,182)	(1,692)	(1,489)
	DUKEXP	0	(674)	674		SOUTHIMP	10,248	1,479	8,770
	DUKIMP	0	173	(173)	WEC		7,076	150	6,926
	NCMPAEXP	0	(0)	0		MISO	7,076	(264)	7,340
	NCMPAIMP	0	489	(489)		SOUTHEXP	0	(2)	2
	SOUTHEXP	(855)	(861)	6		SOUTHIMP	0	416	(416)
	SOUTHIMP	2,507	1,644	863	Grand Total		(18,351)	(19,010)	659
HUDS		(1,993)	(1,993)	0					
	HUDSONTP	(1,993)	(1,993)	0					

Table 9-23 shows the net scheduled and actual PJM flows by interface pricing point and interface. The grouping is reversed from Table 9-22. Table 9-23 shows the interfaces where transactions were scheduled which received the individual interface pricing points. For example, Table 9-23 shows that in 2018, the majority of imports to the PJM energy market for which a market participant specified a generation control area for which it was assigned the IMO interface pricing point, had a path that entered the PJM energy market at the MECS Interface (967 GWh). The majority of exports from the PJM energy market for which a market participant specified a load control area for which it was assigned the IMO interface pricing point, had a path that exited the PJM energy market at the NIPS Interface (-2 GWh).

Table 9-23 Net scheduled and actual flows by interface pricing point and interface (GWh): 2018

Interface Pricing Point	Interface	Actual	Net Scheduled	Difference (GWh)	Interface	Interface Pricing Point	Actual	Net Scheduled	Difference (GWh)
CPLEEXP		0	(236)	236	NEPTUNE		(4,837)	(4,837)	0
	CPLE	0	(236)	236		NEPT	(4,837)	(4,837)	0
CPLEIMP		0	3	(3)	NORTHWEST		0	(3)	3
	CPLE	0	3	(3)		CIN	0	(3)	3
DUKEXP		0	(696)	696	NYIS		(3,451)	(3,379)	(73)
	CPLE	0	(20)	20		NYIS	(3,451)	(3,379)	(73)
	DUK	0	(674)	674	OVEC		3,193	(160)	3,353
	TVA	0	(2)	2		OVEC	3,193	(160)	3,353
DUKIMP		0	303	(303)	SOUTHEAST		0	(1)	1
	CPLE	0	127	(127)		CPLE	0	(1)	1
	CPLW	0	2	(2)	SOUTHEXP		(13,589)	(3,309)	(10,280)
	DUK	0	173	(173)		ALTE	0	(1)	1
HUDSONTP		(1,993)	(1,993)	0		CIN	0	(15)	15
	HUDS	(1,993)	(1,993)	0		CPLE	(1,887)	(584)	(1,303)
IMO		0	1,532	(1,532)		CPLW	(1,120)	(6)	(1,114)
	ALTE	0	490	(490)		DUK	(855)	(861)	6
	ALTW	0	1	(1)		IPL	0	(0)	0
	CIN	0	25	(25)		LGEE	(6,546)	(147)	(6,399)
	IPL	0	50	(50)		MEC	0	(0)	0
	MEC	0	1	(1)		MECS	0	(0)	0
	MECS	0	967	(967)		TVA	(3,182)	(1,692)	(1,489)
	NIPS	0	(2)	2		WEC	0	(2)	2
	NYIS	0	1	(1)	SOUTHIMP		29,635	10,316	19,319
LINDENVFT		(1,761)	(1,761)	0		ALTE	0	171	(171)
	LIND	(1,761)	(1,761)	0		ALTW	0	1	(1)
MISO		(25,547)	(15,902)	(9,645)		AMIL	0	3,051	(3,051)
	ALTE	(3,634)	(3,456)	(178)		CIN	0	390	(390)
	ALTW	(1,916)	(11)	(1,904)		CPLE	5,530	549	4,981
	AMIL	(325)	(4)	(320)		CPLW	109	6	103
	CIN	(5,762)	(5,389)	(372)		DUK	2,507	1,644	863
	CWLP	(34)	0	(34)		IPL	0	45	(45)
	IPL	269	(784)	1,053		LGEE	11,240	1,804	9,436
	MEC	(4,681)	(4,976)	295		MEC	0	16	(16)
	MECS	(7,859)	(1,022)	(6,837)		MECS	0	744	(744)
	NIPS	(8,681)	4	(8,685)		NIPS	0	0	(0)
	TVA	0	0	0		TVA	10,248	1,479	8,770
	WEC	7,076	(264)	7,340		WEC	0	416	(416)
NCMPAEXP		0	(0)	0	Grand Total		(18,351)	(19,010)	659
	DUK	0	(0)	0					
NCMPAIMP		0	1,112	(1,112)					
	CPLE	0	621	(621)					
	CPLW	0	3	(3)					
	DUK	0	489	(489)					

Data Required for Full Loop Flow Analysis

Loop flows are defined as the difference between actual and scheduled power flows at one or more specific interfaces. The differences between actual and scheduled power flows can be the result of a number of underlying causes. To adequately investigate the causes of loop flows, complete data are required.

Loop flows exist because electricity flows on the path of least resistance regardless of the path specified by contractual agreement or regulatory prescription. Loop flows can arise from transactions scheduled into, out of or around a balancing authority on contract paths that do not correspond to the actual physical paths on which energy flows. Outside of LMP-based energy markets, energy is scheduled and paid for based on contract path, without regard to the path of the actual energy flows. Loop flows can also result from actions within balancing authorities.

Loop flows are a significant concern. Loop flows can have negative impacts on the efficiency of markets with explicit locational pricing, including impacts on locational prices, on FTR revenue adequacy and on system operations, and can be evidence of attempts to game such markets. Loop flows also have poorly understood impacts on nonmarket areas. In general, the detailed sources of the identified differences between scheduled and actual flows remain unclear as a result of incomplete or inadequate access to the required data.

A complete analysis of loop flow could provide additional insight that could lead to enhanced overall market efficiency and clarify the interactions among market and nonmarket areas. A complete analysis of loop flow would improve the overall transparency of electricity transactions. There are areas with transparent markets, and there are areas with less transparent markets (nonmarket areas), but these areas together comprise a market, and overall market efficiency would benefit from the increased transparency that would derive from a better understanding of loop flows.

For a complete loop flow analysis, several types of data are required from all balancing authorities in the Eastern Interconnection. The Commission required access to NERC Tag data. In addition to the Tag data, actual tie line data, dynamic schedule and pseudo-tie data are required in order to analyze the differences between actual and scheduled transactions. ACE data, market flow impact data and generation and load data are required in order to understand the sources, within each balancing authority, of loop flows that do not result from differences between actual and scheduled transactions.[43]

NERC Tag Data

An analysis of loop flow requires knowledge of the scheduled path of energy transactions. NERC Tag data include the scheduled path and energy profile of the transactions, including the Generation Control Area (GCA), the intermediate Control Areas, the Load Control Area (LCA) and the energy profile of all transactions. Complete tag data include the identity of the specific market participants. FERC Order No. 771 required access to NERC Tag data for the Commission, regional transmission organizations, independent system operators and market monitoring units.[44]

Actual Tie Line Flow Data

An analysis of loop flow requires knowledge of the actual path of energy transactions. Currently, a very limited set of tie line data is made available via the NERC IDC and the Central Repository for Curtailments (CRC) website. The available tie line data, and the data within the IDC, are presented as information on a screen, which does not permit analysis of the underlying data.

Dynamic Schedule and Pseudo Tie Data

Dynamic schedule and pseudo ties represent another type of interchange transaction between balancing authorities. While dynamic schedules are required to be tagged, the tagged profile is only an estimate of what energy is expected to flow. Dynamic schedules are implemented within each balancing authority's Energy Management System (EMS), with the current values shared over Inter-Control Center Protocol (ICCP) links. By definition, the dynamic schedule scheduled and actual values will always be identical from a balancing authority standpoint, and the tagged profile should be removed from the calculation of loop flows to eliminate double counting of the energy profile. Dynamic schedule data from all balancing authorities are required in order to account for all scheduled and actual flows.

Pseudo-ties are similar to dynamic schedules in that they represent a transaction between balancing authorities and are handled within the EMS systems and data are shared over the ICCP. Pseudo ties differ from dynamic schedules in how the generating resource is modeled within the balancing authorities' ACE equations. Dynamic schedules are modeled as resources located in one area serving load in another, while pseudo ties are modeled as resources in one area moved to another area. Unlike dynamic schedules, pseudo tie transactions are not required to be tagged. Pseudo-tie data from all balancing authorities are required in order to account for all scheduled and actual flows.

Area Control Error (ACE) Data

Area Control Error (ACE) data provides information about how well each balancing authority is matching their generation with their load. This information, combined with the scheduled and actual interchange values will show whether an individual balancing authority is pushing on or leaning on the interconnection, contributing to loop flows.

NERC makes real-time ACE graphs available on their Reliability Coordinator Information System (RCIS) website. This information is presented only in graphical

43 It is requested that all data be made available in downloadable format in order to make analysis possible. A data viewing tool alone is not adequate.

44 141 FERC ¶ 61,235 (2012).

form, and the underlying data is not available for analysis.

Market Flow Impact Data

In addition to interchange transactions, internal dispatch can also affect flows on balancing authorities' tie lines. The impact of internal dispatch on tie lines is called market flow. Market flow data are imported in the IDC, but there is only limited historical data, as only market flow data related to TLR levels 3 or higher are required to be made available via a Congestion Management Report (CMR). The remaining data are deleted.

There is currently a project in development through the NERC Operating Reliability Subcommittee (ORS) called the Market Flow Impact Tool. The purpose of this tool is to make visible the impacts of dispatch on loop flows. The MMU supports the development of this tool, but, equally important, requests that FERC and NERC ensure that the underlying data are provided to market monitors and other approved entities.

Generation and Load Data

Generation data (both real-time scheduled generation and actual output) and load data would permit analysis of the extent to which balancing authorities are meeting their commitments to serve load. If a balancing authority is not meeting its load commitment with adequate generation, the result is unscheduled flows across the interconnections to establish power balance.

Market areas are transparent in providing real-time load while nonmarket areas are not. For example, PJM posts real-time load via its eDATA application. Most nonmarket balancing authorities provide only the expected peak load on their individual web sites. Data on generation are not made publicly available, as this is considered market sensitive information.

The MMU recommends, that in order to permit a complete analysis of loop flow, FERC and NERC ensure that the identified data are made available to market monitors as well as other industry entities determined appropriate by FERC.

PJM and MISO Interface Prices

Both the PJM/MISO and MISO/PJM interface pricing points represent the value of power at the relevant border, as determined in each market. In both cases, the interface price is the price at which transactions are settled. For example, a transaction into PJM from MISO would receive the PJM/MISO interface price upon entering PJM, while a transaction into MISO from PJM would receive the MISO/PJM interface price. PJM and MISO use network models to determine these prices and to attempt to ensure that the prices are consistent with the underlying electrical flows.

Under the PJM/MISO Joint Operating Agreement, the two RTOs mutually determine a set of transmission facilities on which both RTOs have an impact, and therefore jointly operate to those constraints. These jointly controlled facilities are M2M (Market to Market) flowgates. When a M2M constraint binds, PJM's LMP calculations at the buses that make up PJM's MISO interface pricing point are based on the PJM model's distribution factors of the selected buses to the binding M2M constraint and PJM's shadow price of the binding M2M constraint. MISO's LMP calculations at the buses that make up MISO's PJM interface pricing point are based on the MISO model's distribution factors of the selected buses to the binding M2M constraint and MISO's shadow price of the binding M2M constraint.

Prior to June 1, 2014, the PJM interface definition for MISO consisted of nine buses located near the middle of the MISO system and not at the border between the RTOs. The interface definitions led to questions about the level of congestion included in interchange pricing.[45]

PJM modified the definition of the PJM/MISO interface price effective June 1, 2014. PJM's new MISO interface pricing point includes 10 equally weighted buses that are close to the PJM/MISO border. The 10 buses were selected based on PJM's analysis that showed that over 80 percent of the hourly tie line flows between PJM and MISO occurred on 10 ties composed of MISO and PJM monitored facilities. On June 1, 2017, MISO modified their MISO/PJM interface definition to match PJM's PJM/MISO interface definition.

45 See "LMP Aggregate Definitions" (December 12, 2018) <http://www.pjm.com/~/media/markets-ops/energy/lmp-model-info/lmp-aggregate-definitions.ashx>. PJM periodically updates these definitions on its web site. See <http://www.pjm.com>.

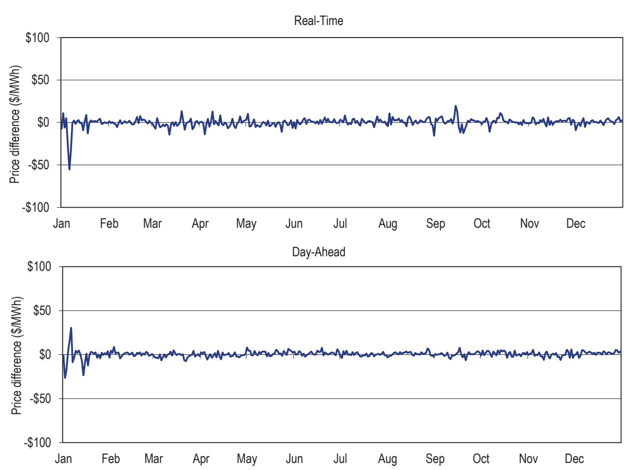
Real-Time and Day-Ahead PJM/MISO Interface Prices

In 2018, the direction of flow was consistent with price differentials in 56.8 percent of the hours. Table 9-24 shows the number of hours and average hourly price differences between the PJM/MISO Interface and the MISO/PJM Interface based on LMP differences and flow direction. Figure 9-4 shows the underlying variability in prices calculated on a daily hourly average basis. There are a number of relevant measures of variability, including the number of times the price differential fluctuates between positive and negative, the standard deviation of individual prices and of price differences and the absolute value of the price differences (Table 9-28).

Table 9-24 PJM and MISO flow based hours and price differences: 2018

LMP Difference	Flow Direction	Number of Hours	Average Hourly Price Difference
MISO/PJM LMP > PJM/MISO LMP	Total Hours	4,977	$6.38
	Consistent Flow (PJM to MISO)	4,914	$6.22
	Inconsistent Flow (MISO to PJM)	63	$18.95
	No Flow	0	$0.00
PJM/MISO LMP > MISO/PJM LMP	Total Hours	3,783	$8.46
	Consistent Flow (MISO to PJM)	66	$29.50
	Inconsistent Flow (PJM to MISO)	3,717	$8.08
	No Flow	1	$2.53

Figure 9-4 Price differences (MISO/PJM Interface minus PJM/MISO Interface): 2018



Distribution and Prices of Hourly Flows at the PJM/MISO Interface

In 2018, the direction of hourly energy flows was consistent with PJM and MISO interface price differentials in 4,980 hours (56.8 percent of all hours), and was inconsistent with price differentials in 3,780 hours (43.2 percent of all hours). Table 9-25 shows the distribution of hourly energy flows between PJM and MISO based on the price differences between the PJM/MISO and MISO/PJM prices. Of the 3,780 hours where flows were in a direction inconsistent with price differences, 3,018 of those hours (79.8 percent) had a price difference greater than or equal to $1.00 and 1,438 of those hours (38.0 percent) had a price difference greater than or equal to $5.00. The largest price difference with such flows was $380.83. Of the 4,980 hours where flows were consistent with price differences, 4,152 of those hours (83.4 percent) had a price difference greater than or equal to $1.00 and 1,499 of all such hours (30.1 percent) had a price difference greater than or equal to $5.00. The largest price difference with such flows was $397.31.

Table 9-25 Distribution of hourly flows that are consistent and inconsistent with price differences between PJM and MISO: 2018

Price Difference Range (Greater Than or Equal To)	Inconsistent Hours	Percent of Inconsistent Hours	Consistent Hours	Percent of Consistent Hours
$0.00	3,780	100.0%	4,980	100.0%
$1.00	3,018	79.8%	4,152	83.4%
$5.00	1,438	38.0%	1,499	30.1%
$10.00	799	21.1%	763	15.3%
$15.00	542	14.3%	478	9.6%
$20.00	384	10.2%	317	6.4%
$25.00	279	7.4%	227	4.6%
$50.00	83	2.2%	65	1.3%
$75.00	39	1.0%	36	0.7%
$100.00	18	0.5%	17	0.3%
$200.00	5	0.1%	3	0.1%
$300.00	1	0.0%	2	0.0%
$400.00	0	0.0%	0	0.0%
$500.00	0	0.0%	0	0.0%

PJM and NYISO Interface Prices

If interface prices were defined in a comparable manner by PJM and the NYISO, if identical rules governed external transactions in PJM and the NYISO, if time lags were not built into the rules governing such transactions and if no risks were associated with such transactions, then prices at the interfaces would be expected to be very close and the level of transactions would be expected to be related to any price differentials. The fact that none of these conditions exists is important in explaining the observed relationship between interface prices and inter-RTO/ISO power flows, and those price differentials.[46]

PJM and NYISO each calculate an interface LMP using network models including distribution factor impacts. Prior to May 1, 2017, PJM used two buses within NYISO to calculate the PJM/NYIS interface pricing point LMP. The NYISO uses proxy buses to calculate interface prices with neighboring balancing authorities. A proxy bus is a single bus, located outside the NYISO footprint, which represents generation and load in a neighboring balancing authority area. The NYISO models imports from PJM as generation at the Keystone proxy bus, delivered to the NYISO reference bus with the assumption that 32 percent of the flow will enter the NYISO across the free flowing A/C ties, 32 percent will enter the NYISO across the Ramapo PARs, 21 percent will enter the NYISO across the ABC PARs and 15 percent will enter the NYISO across the J/K PARs. The NYISO models exports to PJM as being delivered to load at the Keystone proxy bus, sourced from the NYISO reference bus with the assumption that 32 percent of the flow will enter PJM across the free flowing A/C ties, 32 percent will enter PJM across the Ramapo PARs, 21 percent will enter PJM across the ABC PARs and 15 percent will enter PJM across the J/K PARs.

The PJM/NYIS interface definition using two buses was created to include the impact of the ConEd wheeling agreement. The ConEd wheeling agreement ended on May 1, 2017. The end of the wheeling agreement meant that the expected actual power flows would change and therefore the definition of the interface price needed to change. Effective May 1, 2017, PJM replaced the old PJM/NYIS interface price definition. The new PJM/NYIS interface price is based on four buses within NYISO. The four buses were chosen based on a power flow analysis of transfers between PJM and the NYISO and the resultant distribution of flows across the free flowing A/C ties.

Real-Time and Day-Ahead PJM/NYISO Interface Prices

In 2018, the relationship between prices at the PJM/NYIS Interface and at the NYISO/PJM proxy bus and the relationship between interface price differentials and power flows continued to be affected by differences in institutional and operating practices between PJM and the NYISO. The direction of flow was consistent with price differentials in 52.5 percent of the hours in 2018. Table 9-26 shows the number of hours and average hourly price differences between the PJM/NYIS Interface and the NYIS/PJM proxy bus based on LMP differences and flow direction. Figure 9-5 shows the underlying variability in prices calculated on a daily hourly average basis. There are a number of relevant measures of variability, including the number of times the price differential fluctuates between positive and negative, the standard deviation of individual prices and of price differences and the absolute value of the price differences (Table 9-28).

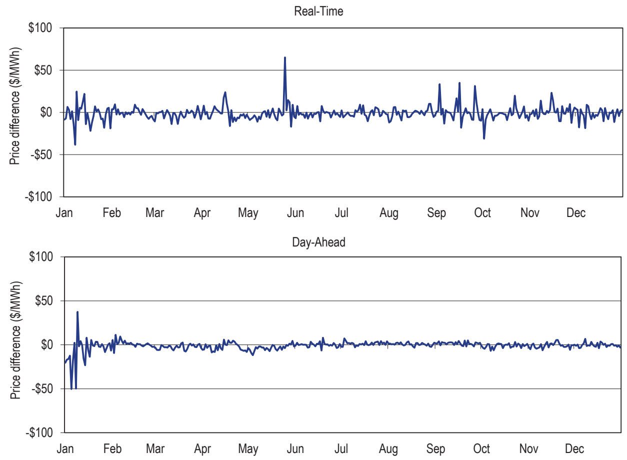
Table 9-26 PJM and NYISO flow based hours and price differences: 2018[47]

LMP Difference	Flow Direction	Number of Hours	Average Hourly Price Difference
NYIS/PJM proxy bus LBMP > PJM/NYIS LMP	Total Hours	3,798	$13.22
	Consistent Flow (PJM to NYIS)	2,991	$12.72
	Inconsistent Flow (NYIS to PJM)	807	$15.06
	No Flow	0	$0.00
PJM/NYIS LMP > NYIS/PJM proxy bus LBMP	Total Hours	4,962	$11.78
	Consistent Flow (NYIS to PJM)	1,611	$10.84
	Inconsistent Flow (PJM to NYIS)	3,351	$12.23
	No Flow	0	$0.00

46 See the *2012 State of the Market Report for PJM*, Volume2, Section 8, "Interchange Transactions," for a more detailed discussion.

47 The NYISO Locational Based Marginal Price (LBMP) is the equivalent term to PJM's Locational Marginal Price (LMP).

Figure 9-5 Price differences (NY/PJM proxy - PJM/NYIS Interface): 2018



Distribution and Prices of Hourly Flows at the PJM/NYISO Interface

In 2018, the direction of hourly energy flows was consistent with PJM/NYISO and NYISO/PJM price differences in 4,602 hours (52.5 percent of all hours), and was inconsistent with price differences in 4,158 hours (47.5 percent of all hours). Table 9-27 shows the distribution of hourly energy flows between PJM and NYISO based on the price differences between the PJM/NYISO and NYISO/PJM prices. Of the 4,158 hours where flows were in a direction inconsistent with price differences, 3,698 of those hours (88.9 percent) had a price difference greater than or equal to $1.00 and 2,186 of all those hours (52.6 percent) had a price difference greater than or equal to $5.00. The largest price difference with such flows was $788.71. Of the 4,602 hours where flows were consistent with price differences, 4,105 of those hours (89.2 percent) had a price difference greater than or equal to $1.00 and 2,411 of all such hours (52.4 percent) had a price difference greater than or equal to $5.00. The largest price difference with such flows was $970.98.

Table 9-27 Distribution of hourly flows that are consistent and inconsistent with price differences between PJM and NYISO: 2018

Price Difference Range (Greater Than or Equal To)	Inconsistent Hours	Percent of Inconsistent Hours	Consistent Hours	Percent of Consistent Hours
$0.00	4,158	100.0%	4,602	100.0%
$1.00	3,698	88.9%	4,105	89.2%
$5.00	2,186	52.6%	2,411	52.4%
$10.00	1,257	30.2%	1,234	26.8%
$15.00	842	20.3%	744	16.2%
$20.00	624	15.0%	564	12.3%
$25.00	490	11.8%	448	9.7%
$50.00	198	4.8%	185	4.0%
$75.00	101	2.4%	98	2.1%
$100.00	66	1.6%	60	1.3%
$200.00	13	0.3%	26	0.6%
$300.00	3	0.1%	10	0.2%
$400.00	3	0.1%	3	0.1%
$500.00	3	0.1%	2	0.0%

Summary of Interface Prices between PJM and Organized Markets

Some measures of the real-time and day-ahead PJM interface pricing with MISO and with the NYISO are summarized and compared in Table 9-28, including average prices and measures of variability.

Table 9-28 PJM, NYISO and MISO border price averages: 2018[48]

		Real-Time		Day-Ahead	
	Description	NYISO	MISO	NYISO	MISO
Average Interval Price	PJM Price at ISO Border	$31.32	$29.49	$34.80	$29.82
	ISO Price at PJM Border	$30.70	$29.97	$33.77	$30.41
	Difference at Border (PJM-ISO)	$0.62	($0.48)	$1.03	($0.59)
	Average Absolute Value of Interval Difference at Border	$42.20	$28.17	$6.55	$4.35
	Sign Changes per Day	34.8	37.7	3.7	3.8
Standard Deviation	PJM Price at ISO Border	$26.60	$21.28	$26.32	$11.70
	ISO Price at PJM Border	$41.84	$25.73	$23.26	$10.92
	Difference at Border (PJM-ISO)	$44.32	$29.57	$7.72	$5.50

Neptune Underwater Transmission Line to Long Island, New York

The Neptune Line is a 65 mile direct current (DC) merchant 230 kV transmission line, with a capacity of 660 MW, providing a direct connection between PJM (Sayreville, New Jersey), and NYISO (Nassau County on Long Island). Schedule 14 of the PJM Open Access Transmission Tariff provides that power flows will only be from PJM to New York. The flows were consistent with price differentials in 60.3 percent of the hours in 2018. Table 9-29 shows the number of hours and average

48 Effective April 1, 2018, PJM implemented 5 minute LMP settlements in the Real-Time Energy Market. The sign changes per day represented in this table reflect the number of intervals where the sign changed per day. For the Real-Time Energy Market, there are 288 five minute intervals. For the Day Ahead Market there are 24 hourly intervals.

hourly price differences between the PJM/NEPT Interface and the NYIS/Neptune bus based on LMP differences and flow direction.

Table 9-29 PJM and NYISO flow based hours and price differences (Neptune): 2018

LMP Difference	Flow Direction	Number of Hours	Average Hourly Price Difference
NYIS/Neptune Bus LBMP > PJM/NEPT LMP	Total Hours	5,727	$18.49
	Consistent Flow (PJM to NYIS)	5,282	$17.53
	Inconsistent Flow (NYIS to PJM)	0	$0.00
	No Flow	445	$29.82
PJM/NEPT LMP > NYIS/Neptune Bus LBMP	Total Hours	3,033	$12.34
	Consistent Flow (NYIS to PJM)	0	$0.00
	Inconsistent Flow (PJM to NYIS)	2,865	$12.50
	No Flow	168	$9.54

To move power from PJM to NYISO using the Neptune Line, two PJM transmission service reservations are required. A transmission service reservation is required from the PJM Transmission System to the Neptune HVDC Line ("Out Service") and another transmission service reservation is required on the Neptune HVDC line ("Neptune Service").[49] The PJM Out Service is covered by normal PJM OASIS business operations.[50] The Neptune Service falls under the provisions for controllable merchant facilities, Schedule 14 of the PJM Tariff. The Neptune Service is also acquired on the PJM OASIS.

Neptune Service is owned by a primary rights holder, and any nonfirm service that is not used (as defined by a schedule on a NERC Tag) may be released either voluntarily by the primary rights holder or by default by PJM. The primary rights holder may elect to voluntarily release monthly, weekly, daily or hourly firm or nonfirm service. Voluntarily releasing the service allows for the primary rights holder to specify a rate to be charged for the released service. If the primary rights holder does not elect to voluntarily release nonfirm service, and does not use the service, the available transmission will be released by default at 12:00, one business day before the start of service. On December 31, 2018, the rate for the nonfirm service released by default was $10 per MWh. The primary rights holder remains obligated to pay for the released service unless a second transmission customer acquires the released service.

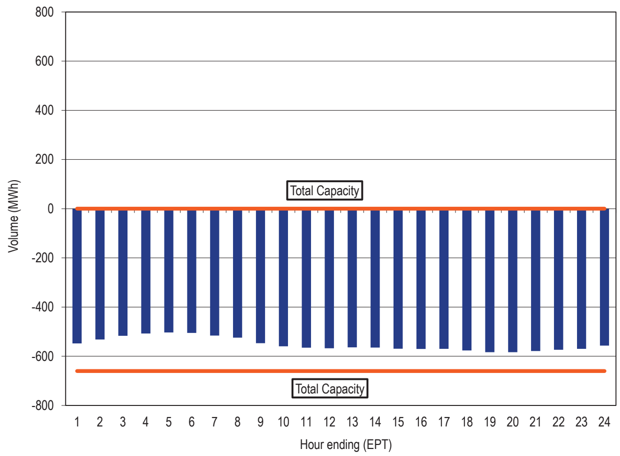
Table 9-30 shows the percent of scheduled interchange across the Neptune Line by the primary rights holder since commercial operations began in July, 2007. Table 9-30 shows that in 2018, the primary rights holder was responsible for 100 percent of the scheduled interchange across the Neptune Line in all months. Figure 9-6 shows the hourly average flow across the Neptune Line for 2018.

Table 9-30 Percent of scheduled interchange across the Neptune line by primary rights holder: July 2007 through 2018

	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
January	NA	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
February	NA	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
March	NA	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
April	NA	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	99.99%	100.00%	100.00%	100.00%
May	NA	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
June	NA	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
July	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
August	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
September	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
October	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
November	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
December	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%

49 See OASIS "PJM Business Practices for Neptune Transmission Service," <http://www.pjm.com/~/media/etools/oasis/merch-trans-facilities/neptune-oasis-Business-practices-doc-clean.ashx>.
50 See OASIS "Regional Transmission and Energy Scheduling Practices," Rev. 7 (December 19, 2018) <http://www.pjm.com/~/media/etools/oasis/regional-practices-clean-pdf.ashx>.

Figure 9-6 Neptune hourly average flow: 2018



Linden Variable Frequency Transformer (VFT) facility

The Linden VFT facility is a controllable AC merchant transmission facility, with a capacity of 315 MW, providing a direct connection between PJM (Linden, New Jersey) and NYISO (Staten Island, New York). The flows were consistent with price differentials in 58.9 percent of the hours in 2018. Table 9-31 shows the number of hours and average hourly price differences between the PJM/LIND Interface and the NYIS/Linden bus based on LMP differences and flow direction.

Table 9-31 PJM and NYISO flow based hours and price differences (Linden): 2018

LMP Difference	Flow Direction	Number of Hours	Average Hourly Price Difference
NYIS/Linden Bus LBMP > PJM/LIND LMP	Total Hours	5,290	$14.13
	Consistent Flow (PJM to NYIS)	5,158	$14.21
	Inconsistent Flow (NYIS to PJM)	0	$0.00
	No Flow	132	$10.97
PJM/LIND LMP > NYIS/Linden Bus LBMP	Total Hours	3,470	$20.62
	Consistent Flow (NYIS to PJM)	0	$0.00
	Inconsistent Flow (PJM to NYIS)	3,372	$20.89
	No Flow	98	$11.31

To move power from PJM to NYISO on the Linden VFT Line, two PJM transmission service reservations are required. A transmission service reservation is required from the PJM Transmission System to the Linden VFT ("Out Service") and another transmission service reservation is required on the Linden VFT ("Linden VFT Service").[51] The PJM Out Service is covered by normal PJM OASIS business operations.[52] The Linden VFT Service falls under the provisions for controllable merchant facilities, Schedule 16 and Schedule 16-A of the PJM Tariff. The Linden VFT Service is also acquired on the PJM OASIS.

Linden VFT Service is owned by a primary rights holder, and any nonfirm service that is not used (as defined by a schedule on a NERC Tag) may be released either voluntarily by the primary rights holder or by default by PJM. The primary rights holder may elect to voluntarily release monthly, weekly, daily or hourly firm or nonfirm service. Voluntarily releasing the service allows for the primary rights holder to specify a rate to be charged for the released service. If the primary rights holder elects to not voluntarily release nonfirm service, and does not use the service, the available transmission will be released by default at 12:00, one business day before the start of service. On December 31, 2018, the rate for the nonfirm service released by default was $6.00 per MWh. The primary rights holder remains obligated to pay for the released service unless a second transmission customer acquires the released service.

Table 9-32 shows the percent of scheduled interchange across the Linden VFT Line by the primary rights holder since commercial operations began in November, 2009. Table 9-32 shows that in 2018, the primary rights holder was responsible for 100 percent of the scheduled interchange across the Linden VFT Line in all months. Figure 9-7 shows the hourly average flow across the Linden VFT Line for 2018.

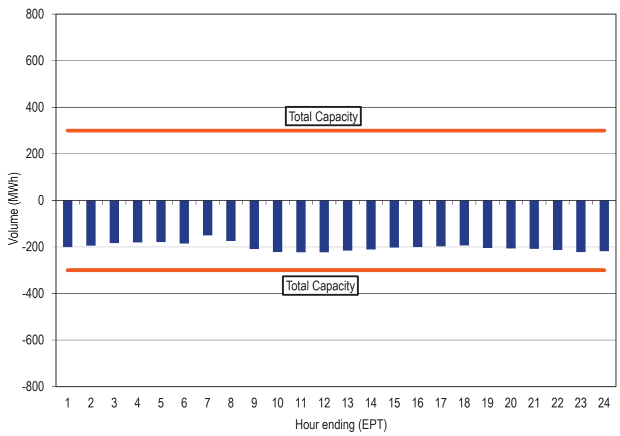
51 See OASIS "PJM Business Practices for Linden VFT Transmission Service," <http://www.pjm.com/~/media/etools/oasis/merch-trans-facilities/linden-vft-oasis-Business-practices-doc-clean.ashx>.

52 See OASIS "Regional Transmission and Energy Scheduling Practices," Rev. 7 (December 19, 2018) <http://www.pjm.com/~/media/etools/oasis/regional-practices-clean-doc.ashx>.

Table 9-32 Percent of scheduled interchange across the Linden VFT Line by primary rights holder: November 2009 through 2018

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
January	NA	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	70.53%	100.00%	100.00%
February	NA	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	94.95%	100.00%	100.00%
March	NA	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	96.46%	100.00%	100.00%
April	NA	99.97%	100.00%	100.00%	100.00%	99.98%	100.00%	49.32%	100.00%	100.00%
May	NA	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
June	NA	100.00%	100.00%	100.00%	100.00%	27.27%	100.00%	100.00%	100.00%	100.00%
July	NA	100.00%	100.00%	100.00%	100.00%	29.56%	100.00%	100.00%	100.00%	100.00%
August	NA	100.00%	100.00%	100.00%	100.00%	82.46%	100.00%	100.00%	100.00%	100.00%
September	NA	100.00%	100.00%	100.00%	100.00%	81.68%	100.00%	100.00%	100.00%	100.00%
October	NA	100.00%	100.00%	100.00%	100.00%	100.00%	35.05%	100.00%	100.00%	100.00%
November	100.00%	100.00%	100.00%	100.00%	99.86%	100.00%	61.45%	100.00%	100.00%	100.00%
December	100.00%	100.00%	100.00%	98.22%	100.00%	100.00%	84.57%	100.00%	100.00%	100.00%

Figure 9-7 Linden hourly average flow: 2018[53]



Hudson Direct Current (DC) Merchant Transmission Line

The Hudson direct current (DC) Line is a bidirectional merchant 230 kV transmission line, with a capacity of 673 MW, providing a direct connection between PJM (Public Service Electric and Gas Company's (PSE&G) Bergen 230 kV Switching Station located in Ridgefield, New Jersey) and NYISO (Consolidated Edison's (Con Ed) W. 49th Street 345 kV Substation in New York City). The connection is a submarine cable system. While the Hudson DC Line is a bidirectional line, power flows are only from PJM to New York because the Hudson Transmission Partners, LLC had only requested withdrawal rights (320 MW of firm withdrawal rights, and 353 MW of nonfirm withdrawal rights). The flows were consistent with price differentials in 56.7 percent of the hours in 2018. Table 9-33 shows the number of hours and average hourly price differences between the PJM/HUDS Interface and the NYIS/Hudson bus based on LMP differences and flow direction.

Table 9-33 PJM and NYISO flow based hours and price differences (Hudson): 2018

LMP Difference	Flow Direction	Number of Hours	Average Hourly Price Difference
NYIS/Hudson Bus LBMP > PJM/HUDS LMP	Total Hours	5,006	$14.20
	Consistent Flow (PJM to NYIS)	4,964	$14.24
	Inconsistent Flow (NYIS to PJM)	0	$0.00
	No Flow	42	$9.86
PJM/HUDS LMP > NYIS/Hudson Bus LBMP	Total Hours	3,754	$12.30
	Consistent Flow (NYIS to PJM)	0	$0.00
	Inconsistent Flow (PJM to NYIS)	3,738	$12.29
	No Flow	16	$16.03

53 The Linden VFT Line is a bidirectional facility. The "Total Capacity" lines represent the maximum amount of interchange possible in either direction. These lines were included to maintain a consistent scale, for comparison purposes, with the Neptune DC Tie Line.

To move power from PJM to NYISO on the Hudson Line, two PJM transmission service reservations are required. A transmission service reservation is required from the PJM Transmission System to the Hudson Line ("Out Service") and another transmission service reservation is required on the Hudson Line ("Hudson Service").[54] The PJM Out Service is covered by normal PJM OASIS business operations.[55] The Hudson Service falls under the provisions for controllable merchant facilities, Schedule 17 of the PJM Tariff. The Hudson Service is also acquired on the PJM OASIS.

Hudson Service is owned by a primary rights holder, and any nonfirm service that is not used (as defined by scheduled on a NERC Tag) may be released either voluntarily by the primary rights holder or by default by PJM. The primary rights holder may elect to voluntarily release monthly, weekly, daily or hourly firm or nonfirm service. Voluntarily releasing the service allows for the primary rights holder to specify a rate to be charged for the released service. If the primary rights holder elects to not voluntarily release nonfirm service, and does not use the service, the available transmission will be released by default at 12:00, one business day before the start of service. On December 31, 2018, the rate for the nonfirm service released by default was $10 per MWh. The primary rights holder remains obligated to pay for the released service unless a second transmission customer acquires the released service.

Table 9-34 shows the percent of scheduled interchange across the Hudson Line by the primary rights holder since commercial operations began in May, 2013. Table 9-34 shows that in 2018, the primary rights holder was responsible for less than 100 percent of the scheduled interchange across the Hudson line in all months. Figure 9-8 shows the hourly average flow across the Hudson Line for 2018.

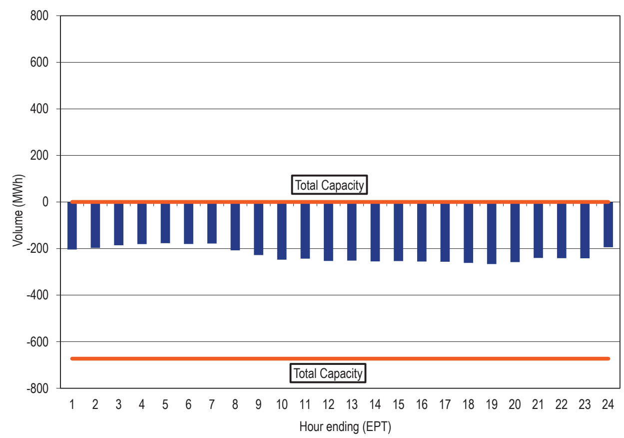
54 See OASIS "PJM Business Practices for Hudson Transmission Service,"<http://www.pjm.com/~/media/etools/oasis/merch-trans-facilities/htp-Business-practices.ashx>.

55 See OASIS "Regional Transmission and Energy Scheduling Practices," Rev. 7 (December 19, 2018) <http://www.pjm.com/~/media/etools/oasis/regional-practices-clean-doc.ashx>.

Table 9-34 Percent of scheduled interchange across the Hudson Line by primary rights holder: May 2013 through 2018

	2013	2014	2015	2016	2017	2018
January	NA	51.22%	16.27%	100.00%	NA	24.44%
February	NA	49.00%	14.67%	NA	NA	23.25%
March	NA	40.40%	71.88%	NA	NA	9.55%
April	NA	100.00%	100.00%	NA	NA	15.13%
May	100.00%	26.87%	100.00%	100.00%	NA	92.18%
June	100.00%	5.89%	59.72%	100.00%	NA	44.89%
July	100.00%	18.51%	84.34%	NA	NA	16.26%
August	100.00%	75.17%	65.48%	NA	NA	19.24%
September	100.00%	75.31%	78.73%	NA	NA	22.90%
October	100.00%	99.71%	18.65%	100.00%	NA	22.67%
November	85.57%	99.60%	24.67%	100.00%	80.12%	50.44%
December	28.32%	1.68%	100.00%	NA	21.93%	29.38%

Figure 9-8 Hudson hourly average flow: 2018



Interchange Activity During High Load Hours

The PJM metered system peak load during 2018 was 147,042 MW in the HE 1700 on August 28, 2018. PJM was under a hot weather alert in that hour. PJM did not make any emergency energy purchases or sales in that hour. PJM was a net scheduled exporter of energy in all hours on August 28, 2018, with average hourly scheduled exports of 4,223 MW. During HE 1700 on June 18, 2018, PJM had net scheduled exports of 3,445 MW and net metered actual exports of 3,442 MW. Net transaction exports during this time were consistent with the price differences between PJM and its neighboring balancing authority areas. During the month of August 2018, PJM was a net scheduled exporter of energy in all hours. During August 2018, the average hourly scheduled interchange was -3,678 MW (representing 3.6 percent of the average hourly load of 102,154 MW in August, 2018).

Operating Agreements with Bordering Areas

To improve reliability and reduce potential seams issues, PJM and its neighbors have developed operating agreements, including: operating agreements with MISO and the NYISO; a reliability agreement with TVA; an operating agreement with Duke Energy Progress, Inc.; a reliability coordination agreement with VACAR South; a balancing authority operations agreement with the Wisconsin Electric Power Company (WEC); and a Northeastern planning coordination protocol with NYISO and ISO New England.

Table 9-35 shows a summary of the elements included in each of the operating agreements PJM has with its bordering areas.

Table 9-35 Summary of elements included in operating agreements with bordering areas

Agreement:	PJM-MISO	PJM-NYISO	PJM-TVA	PJM-DEP	PJM-VACAR	PJM-WEP	Northeastern Protocol
Data Exhange							
Real-Time Data	YES	YES	YES	YES	YES	YES	NO
Projected Data	YES	YES	YES	YES	NO	NO	NO
SCADA Data	YES	YES	YES	YES	NO	NO	NO
EMS Models	YES	YES	YES	YES	NO	NO	YES
Operations Planning Data	YES	YES	YES	YES	NO	NO	YES
Available Flowgate Capability Data	YES	YES	YES	YES	NO	NO	YES
Near-Term System Coordination							
Operating Limit Violation Assistance	YES	YES	YES	YES	YES	NO	NO
Over/Under Voltage Assistance	YES	YES	YES	YES	YES	NO	NO
Emergency Energy Assistance	YES	YES	NO	YES	YES	NO	NO
Outage Coordination	YES	YES	YES	YES	YES	NO	NO
Long-Term System Coordination	YES	YES	YES	YES	NO	NO	YES
Congestion Management Process							
ATC Coordination	YES	YES	YES	YES	NO	NO	NO
Market Flow Calculations	YES	YES	YES	NO	NO	NO	NO
Firm Flow Entitlements	YES	YES	YES	NO	NO	NO	NO
Market to Market Redispatch	YES - Redispatch	YES - Redispatch	NO	YES - Dynamic Schedule	NO	NO	NO
Joint Checkout Procedures	YES	YES	YES	YES	NO	YES	NO

PJM-MISO = MISO/PJM Joint Operating Agreement
PJM-NYISO = New York ISO/PJM Joint Operating Agreement
PJM-TVA = Joint Reliablity Coordination Agreement Between PJM - Tennessee Valley Authority (TVA)
PJM-DEP = Duke Energy Progress (DEP) - PJM Joint Operating Agreement
PJM-VACAR = PJM-VACAR South Reliability Coordination Agreement
PJM-WEP = Balancing Authority Operations Coordination Agreement Between Wisconsin Electric Power Company and PJM Interconnection, LLC
Northeastern Protocol = Northeastern ISO-Regional Transmission Organization Planning Coordination Protocol

PJM and MISO Joint Operating Agreement[56]

The Joint Operating Agreement between MISO and PJM Interconnection, L.L.C. was executed on December 31, 2003. The PJM/MISO JOA includes provisions for market based congestion management that, for designated flowgates within MISO and PJM, allow for redispatch of units within the PJM and MISO regions to jointly manage congestion on these flowgates and to assign the costs of congestion management appropriately. In 2012, MISO and PJM initiated a joint stakeholder process to address issues associated with the operation of the markets at the seam.[57]

Under the market to market rules, the organizations coordinate pricing at their borders. PJM and MISO each calculate an interface LMP using network models

56 See "Joint Operating Agreement Between the Midwest Independent Transmission System Operator, Inc. and PJM Interconnection, L.L.C." (December 11, 2008) <http://www.pjm.com/directory/merged-tariffs/miso-joa.pdf>.

57 See "PJM/MISO Joint and Common Market Initiative," <http://www.pjm.com/committees-and-groups/stakeholder-meetings/pjm-miso-joint-common.aspx>.

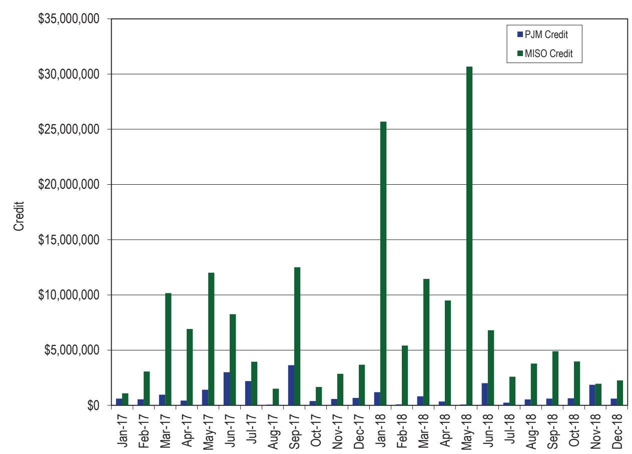
including distribution factor impacts. PJM uses 10 buses along the PJM/MISO border to calculate the PJM/MISO interface pricing point LMP. Prior to June 1, 2017, MISO used all of the PJM generator buses in its model of the PJM system in its calculation of the MISO/PJM interface pricing point.[58] On June 1, 2017, MISO modified their MISO/PJM interface definition to match PJM's PJM/MISO interface definition.[59]

An operating entity is an entity that operates and controls a portion of the bulk transmission system with the goal of ensuring reliable energy interchange between generators, loads and other operating entities.[60] Coordinated flowgates are identified to determine which flowgates an operating entity affects significantly. This set of flowgates may then be used in the congestion management process. An operating entity will conduct sensitivity studies to determine which flowgates are significantly affected by the flows of the operating entity's control zones (historic control areas that existed in the IDC). An operating entity identifies these flowgates by performing five studies to determine which flowgates the operating entity will monitor and help control. These studies include generation to load distribution factor studies, transfer distribution factor analysis and an external asynchronous resource study. An operating entity may also specify additional flowgates that have not passed any of the five studies to be coordinated flowgates where the operating entity expects to use the TLR process to manage congestion.[61] A reciprocal coordinated flowgate (RCF) is a CF that is monitored and controlled by PJM or MISO, on which both have significant impacts. Only RCFs are subject to the market to market congestion management process.

As of January 1, 2018, PJM had 140 flowgates eligible for M2M (Market to Market) coordination. In 2018, PJM added 34 flowgates and deleted 37 flowgates, leaving 137 flowgates eligible for M2M coordination as of December 31, 2018. As of January 1, 2018, MISO had 234 flowgates eligible for M2M coordination. In 2018, MISO added 134 flowgates and deleted 129 flowgates, leaving 239 flowgates eligible for M2M coordination as of December 31, 2018.

The firm flow entitlement (FFE) represents the amount of historic 2004 flow that each RTO had created on each RCF used in the market to market settlement process. The FFE establishes the amount of market flow that each RTO is permitted to create on the RCF before incurring redispatch costs during the market to market process. If the nonmonitoring RTO's real-time market flow is greater than their FFE plus the approved MW adjustment from day-ahead coordination, then the non-monitoring RTO will pay the monitoring RTO based on the difference between their market flow and their FFE. If the non-monitoring RTO's real-time market flow is less than their FFE plus the approved MW adjustment from day-ahead coordination, then the monitoring RTO will pay the nonmonitoring RTO for congestion relief provided by the non-monitoring RTO based on the difference between the nonmonitoring RTO's market flow and their FFE. In 2018, market to market operations resulted in MISO and PJM redispatching units to control congestion on M2M flowgates and the exchange of payments for this redispatch. Figure 9-9 shows credits for coordinated congestion management between PJM and MISO.

Figure 9-9 PJM/MISO credits for coordinated congestion management: 2017 through 2018[62]



58 See the *2012 State of the Market Report for PJM*, Volume 2, Section 8, "Interchange Transactions," for a more detailed discussion.

59 See "Joint and Common Market: MISO-PJM Interface Pricing Update" (November 15, 2016) <http://www.pjm.com/~/media/committees-groups/stakeholder-meetings/pjm-miso-joint-common/20161115/20161115-item-03a-interface-pricing-post-implementation.ashx>.

60 See "Joint Operating Agreement Between the Midwest Independent Transmission System Operator, Inc. and PJM Interconnection, L.L.C." (December 11, 2008) <http://www.pjm.com/directory/merged-tariffs/miso-joa.pdf>.

61 See "Joint Operating Agreement Between the Midwest Independent Transmission System Operator, Inc. and PJM Interconnection, L.L.C." (December 11, 2008) <http://www.pjm.com/directory/merged-tariffs/miso-joa.pdf>.

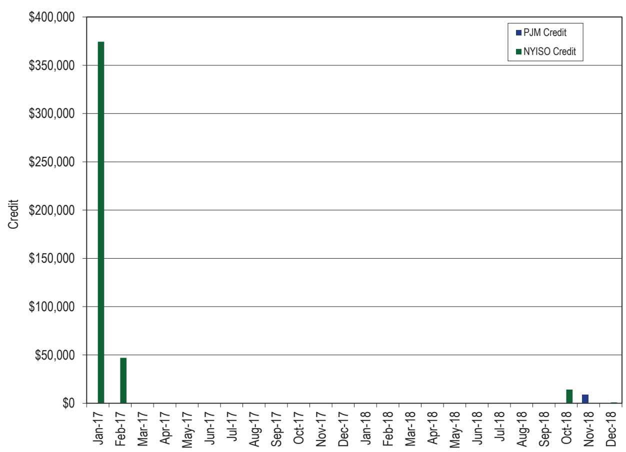
62 The totals represented in this figure represent the settlements as of the time of this report and may not include adjustments or resettlements.

PJM and New York Independent System Operator Joint Operating Agreement (JOA)[63]

The Joint Operating Agreement between NYISO and PJM Interconnection, L.L.C. became effective on January 15, 2013. Under the market to market rules, the organizations coordinate pricing at their borders.

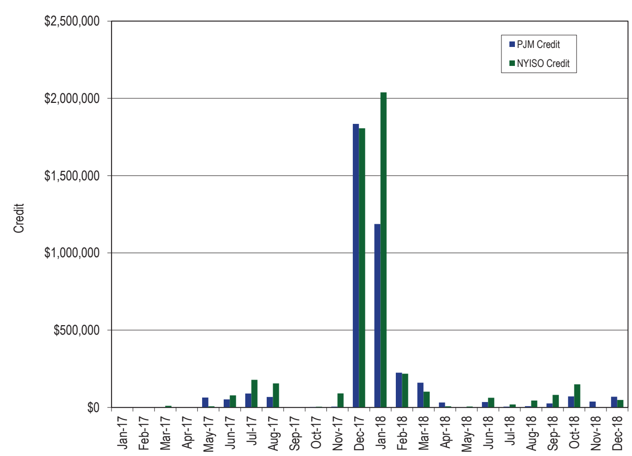
In 2018, market to market operations resulted in NYISO and PJM redispatching units to control congestion on M2M flowgates and the exchange of payments for this redispatch. Figure 9-10 shows credits for coordinated congestion management between PJM and NYISO.

Figure 9-10 PJM/NYISO credits for coordinated congestion management (flowgates): 2017 through 2018[64]



The M2M coordination process focuses on real-time market coordination to manage transmission limitations that occur on M2M flowgates in a cost effective manner. Coordination between NYISO and PJM includes not only joint redispatch, but also incorporates coordinated operation of the PARs that are located at the PJM/NYIS border. This real-time coordination results in an efficient economic dispatch solution across both markets to manage the real-time transmission constraints that impact both markets, focusing on the actual flows in real time to manage constraints.[65] For each M2M flowgate, a PAR settlement will occur for each interval during coordinated operations. The PAR settlements are determined based on whether the measured real-time flow on each of the PARs is greater than or less than the calculated target value. If the actual flow is greater than the target flow, NYISO will make a payment to PJM. This payment is calculated as the product of the M2M flowgate shadow price, the PAR shift factor and the difference between the actual and target PAR flow. If the actual flow is less than the target flow, PJM will make a payment to NYISO. This payment is calculated as the product of the M2M flowgate shadow price, the PAR shift factor and the difference between the target and actual PAR flow. Effective May 1, 2017, coincident with the termination of the ConEd wheel, PJM and NYISO began M2M coordination at all of the PARs along the PJM/NYISO seam. Prior to May 1, 2017, only the Ramapo PARs were included in the M2M process. In 2018, market to market operations resulted in NYISO and PJM adjusting PARs to control congestion and the exchange of payments for this coordination. Figure 9-11 shows the PAR credits for coordinated congestion management between PJM and NYISO. The large increase in PAR credits in December 2017 and January 2018 was due to system operations coordination during the extreme temperatures in the final week of 2017 and the first week of 2018.

Figure 9-11 PJM/NYISO credits for coordinated congestion management (PARs): 2017 through 2018[66]



63 See "New York Independent System Operator, Inc., Joint Operating Agreement with PJM Interconnection, L.L.C." (June 21, 2017) <http://www.pjm.com/~/media/documents/agreements/nyiso-joa.ashx>.

64 The totals represented in this figure represent the settlements as of the time of this report and may not include adjustments or resettlements.

65 See "New York Independent System Operator, Inc., Joint Operating Agreement with PJM Interconnection, L.L.C." (June 21, 2017) <http://www.pjm.com/~/media/documents/agreements/nyiso-joa.ashx>.

66 The totals represented in this figure represent the settlements as of the time of this report and may not include adjustments or resettlements.

PJM and TVA Joint Reliability Coordination Agreement (JRCA)[67]

The joint reliability coordination agreement (JRCA) executed on April 22, 2005, provides for the exchange of information and the implementation of reliability and efficiency protocols between TVA and PJM. The agreement also provides for the management of congestion and arrangements for both near-term and long-term system coordination. Under the JRCA, PJM and TVA honor constraints on the other's flowgates in their Available Transmission Capability (ATC) calculations. Market flows are calculated on reciprocal flowgates. When a constraint occurs on a reciprocal flowgate within TVA, PJM has the option to redispatch generation to reduce market flow, and therefore alleviate the constraint. Unlike the M2M procedure between MISO and PJM, this redispatch does not result in M2M payments. However, electing to redispatch generation within PJM can avoid potential market disruption by curtailing transactions under the Transmission Line Loading Relief (TLR) procedure to achieve the same relief. The agreement remained in effect in 2018.

PJM and Duke Energy Progress, Inc. Joint Operating Agreement[68]

On September 9, 2005, the FERC approved a JOA between PJM and Progress Energy Carolinas, Inc. (PEC), with an effective date of July 30, 2005. As part of this agreement, both parties agreed to develop a formal congestion management protocol (CMP). On February 2, 2010, PJM and PEC filed a revision to the JOA to include a CMP.[69] On January 20, 2011, the Commission conditionally accepted the compliance filing. On July 2, 2012, Duke Energy and Progress Energy Inc. completed a merger. At that time, Progress Energy Carolinas Inc., now a subsidiary of Duke, changed its name to Duke Energy Progress (DEP).

The PJM/DEP JOA states that the Marginal Cost Proxy Method (MCPM) will be used in the determination of the CPLEIMP and CPLEEXP interface price. Section 2.6A (2) of the PJM Tariff describes the process of calculating the interface price under the MCPM. Under the MCPM, PJM compares the individual bus LMP (as calculated by PJM) for each DEP generator in the PJM model with a telemetered output greater than zero MW to the marginal cost for that generator.

For the CPLEIMP price (imports to PJM), PJM uses the lowest LMP of any generator bus in the DEP balancing authority area, with an output greater than zero MW that has an LMP less than its marginal cost for each five minute interval. If no generator with an output greater than zero MW has an LMP less than its marginal cost, then the import price is the average of the bus LMPs for the set of generators in the DEP area with an output greater than zero MW that PJM determines to be the marginal units in the DEP area for that five minute interval. PJM determines the marginal units in the DEP area by summing the output of the units serving load in the DEP area in ascending order by the units' marginal costs until the sum equals the real-time load in the DEP area. Units in the DEP area with marginal costs at or above that of the last unit included in the sum are the marginal units for the DEP area for that interval.

PJM calculates the CPLEEXP price for exports from PJM to DEP as the highest LMP of any generator bus in the DEP area with an output greater than zero MW (excluding nuclear and hydro units) that has an LMP greater than its marginal cost in the 5 minute interval.[70] If no generator with an output greater than zero MW has an LMP greater than its marginal cost, then the export price will be the average of the bus LMPs for the set of generators with an output greater than zero MW that PJM determines to the be marginal units in the same manner as described for the CPLEIMP interface price. The hourly integrated import and export prices are the average of all of the 5 minute intervals in each hour.

The MCPM calculation is based on the DEP units modeled in the PJM market that have an output greater than zero, and only uses the units whose output exceeds the reported DEP real-time load. When new units are added to the DEP footprint, and existing units in the DEP footprint retire, PJM does not have complete data to calculate the interface price. These new units

67 See "Joint Reliability Coordination Agreement Among and Between PJM Interconnection, L.L.C., and Tennessee Valley Authority" (October 15, 2014) <http://www.pjm.com/~/media/documents/agreements/joint-reliability-coordination-agreement-miso-pjm-tva.ashx>.

68 See "Amended and Restated Joint Operating Agreement Among and Between PJM Interconnection, L.L.C., and Duke Energy Progress Inc." (December 3, 2014) <http://www.pjm.com/directory/merged-tariffs/progress-joa.pdf>.

69 See *PJM Interconnection, L.L.C and Progress Energy Carolinas, Inc.* Docket No. ER10-713-000 (February 2, 2010).

70 The MMU has objected to the omission of nuclear and hydro units from the calculation. This omission is not included in the definition of the MCPM interface pricing method in the PJM Tariff, but is included as a special condition in the PJM/DEP JOA. The MMU does not believe it is appropriate to exclude these units from the calculation as these units could be considered marginal and affect the prices.

can impact the interface price in several ways. By not having the additional units modeled, these units cannot be considered to be marginal units, and therefore cannot set price. For the import price, if the PJM calculated LMP of one of the new units were to be lower than any currently modeled unit, then PJM's CPLEIMP pricing point would be lower, and PJM would pay less for imports. If the PJM calculated LMP of one of the new units were to be higher than any currently modeled unit, then PJM's CPLEEXP pricing point would be higher, and PJM would receive more for exports.

Not maintaining a current set of units in the DEP footprint in PJM's network model limits PJM's ability to recognize which units are marginal and it is often not possible to calculate the CPLEIMP and CPLEEXP interface prices using the MCPM. By not maintaining a complete set of units in the DEP footprint, the reported output of the modeled units are often insufficient to cover the reported real-time load, and therefore no units are considered marginal. When this occurs, the MMU believes that the CPLEIMP and CPLEEXP pricing points should revert to the SOUTHIMP and SOUTHEXP interface prices, but this has not happened. When this occurs, PJM uses the high-low interface pricing method as described in Section 2.6A (1) of the PJM Tariff. The MMU does not believe that this is appropriate, and does not see the basis for this approach in either the PJM Tariff or the PJM/DEP JOA.

On July 2, 2012, Duke Energy and Progress Energy Inc. completed a merger. While the individual companies planned to operate separately for a period of time, they have a joint dispatch agreement, and a joint open access transmission tariff.[71] On October 3, 2014, Duke Energy Progress (DEP) and PJM submitted revisions to the JOA to include a new Appendix B, update references to DEP's current legal name, and incorporate other revisions.[72] The MMU submitted a protest to this filing noting that the existing JOA depends on the specific characteristics of PEC as a standalone company, and the assumptions reflected in the current JOA no longer apply under the DEP joint dispatch agreement.[73] As noted in the 2010 filing, "the terms and conditions of the bilateral agreement among PEC and PJM are grounded in an appreciation of their systems as they exist at the time of the effective date of the JOA, but they fully expect that evolving circumstances, protocols and requirements will require that they negotiate, in good faith, a response to such changes."[74] The joint dispatch agreement changed the unique operational relationship that existed when the congestion management protocol was established. However, the merged company has not engaged in discussions with PJM as to whether the congestion management protocol that was "tailored to their [PJM and PEC] unique operational relationship" is still appropriate, or whether the congestion management protocol needs to be revised. The existing JOA does not apply to the merged company and should be terminated.

Article 14 of the JOA provides details of the PJM/DEP congestion management agreement (CMA). The purpose of the CMA is to allow "DEP to quickly respond to the LMP values sent by PJM to DEP. This quick response will help manage the congestion on the PJM transmission system by maintaining flows within established limits and stabilizing PJM LMP values, and will help reduce the need to use the TLR process to relieve the congestion by maintaining power flows within established reliability limits." Congestion is managed by using a dynamic schedule between CPLE and PJM. DEP responds to the dynamic pricing signal sent by PJM by increasing generation, which creates energy flow in the direction from CPLE to PJM or by decreasing generation, which creates energy flow in the direction from PJM to CPLE. The dynamic schedule calls for more DEP generation when the DEP marginal cost of online generation is less than the CPLE LMP, and it calls for less DEP generation when the DEP marginal cost exceeds the CPLE LMP. The economic energy flow on the dynamic schedule reduces congestion.

The amount of congestion relief is limited by the amount of energy that can flow on the dynamic schedule. Several factors determine this limit, including: the physical limitations of DEP's units; ATC limits on the transmission path between CPLE and PJM; the actual confirmed transmission acquired in advance by DEP. Section 14.4.1 of the JOA states that:

71 See "Duke Energy Carolinas, LLC, Carolina Power & Light tariff filing," Docket No. ER12-1338-000 (July 12, 2012) and "Duke Energy Carolinas, LLC, Carolina Power & Light Joint Dispatch Agreement filing," Docket No. ER12-1343-000 (July 11, 2012).

72 See *Duke Energy Progress, Inc. and PJM Interconnection, L.L.C*, Docket No. ER15-29-000 (October 3, 2014).

73 See Protest and Motion for Rehearing of the Independent Market Monitor for PJM in Docket No. ER15-29-000 (October 24, 2014).

74 Joint Motion for Leave to Answer and Answer of PJM Interconnection, L.C.C. and Progress Energy Carolinas, Inc., Docket No. ER10-713-000 (March 10, 2010) at 2. Section 3.3 of the PJM-Progress JOA.

> The transmission service used on the DEP transmission system to support the process described in this Article will be a non-firm point to point reservation from DEP to PJM made by DEP. The Dynamic Schedule will be limited to the point to point reservation. The transmission service used on the PJM transmission system will be network secondary service.

In 2018, DEP acquired the required transmission service in only 94 of the 8,760 hours (1.1 percent of all hours), with an average capacity of approximately 159 MW. At most, DEP could have increased their generation to help manage constraints via a sale of power to PJM 1.1 percent of the time in 2018, and the maximum redispatch would have been only 159 MW, on average.

A CMA that can only be used in 1.1 percent of all hours is not an effective approach to congestion management. For that reason and based on the significant flaws in the agreement, the MMU recommends that PJM immediately provide the required 12-month notice to DEP to unilaterally terminate the Joint Operating Agreement.

PJM and VACAR South Reliability Coordination Agreement[75]

On May 23, 2007, PJM and VACAR South (comprised of Duke Energy Carolinas, LLC (DUK), DEP, South Carolina Public Service Authority (SCPSA), Southeast Power Administration (SEPA), South Carolina Energy and Gas Company (SCE&G) and Yadkin Inc. (a part of Alcoa)) entered into a reliability coordination agreement which provides for system and outage coordination, emergency procedures and the exchange of data. The parties meet on a yearly basis. The agreement remained in effect in 2018.

Balancing Authority Operations Coordination Agreement between Wisconsin Electric Power Company (WEC) and PJM Interconnection, LLC[76]

The Balancing Authority Operations Coordination Agreement executed on July 20, 2013, provides for the exchange of information between WEC and PJM. The purpose of the data exchange is to allow for the coordination of balancing authority actions to ensure the reliable operation of the systems. The agreement remained in effect in 2018.

Northeastern ISO-Regional Transmission Organization Planning Coordination Protocol[77]

The Northeastern ISO-RTO Planning Coordination Protocol executed on December 8, 2004, provides for the exchange of information among PJM, NYISO and ISO New England. The purpose of the data exchange is to allow for the long-term planning coordination among and between the ISOs and RTOs in the Northeast. The agreement remained in effect in 2018.

Interface Pricing Agreements with Individual Balancing Authorities

PJM consolidated the Southeast and Southwest interface pricing points to a single interface with separate import and export prices (SouthIMP and SouthEXP) on October 31, 2006.

The PJM/DEP JOA allows for the CPLEIMP and CPLEEXP interface pricing points to be calculated using the Marginal Cost Proxy Pricing method.[78] The DUKIMP, DUKEXP, NCMPAIMP and NCMPAEXP interface pricing points are calculated based on the high-low pricing method as defined in Section 2.6A (1) of the PJM Tariff.

Table 9-36 shows the real-time LMP calculated per the PJM/DEP JOA and the high/low pricing method used by Duke and NCMPA for 2018. The values shown in Table 9-36 are the average LMP over only the hours in 2018 where interchange transactions settled at those pricing points. The difference between the LMP under these agreements and PJM's SouthIMP LMP ranged from $0.40 with Duke to $6.00 with PEC.[79] This means that under the specific interface pricing agreements, transactions settling at the Duke interface price would receive, on average, $0.40 more for importing energy into PJM than if they were to receive the SouthIMP pricing point. In 2018, market participants received $176,558 more for importing energy using this pricing

75 See "PJM-VACAR South RC Agreement" (November 7, 2014) <http://www.pjm.com/~/media/documents/agreements/executed-pjm-vacar-rc-agreement.ashx>.

76 See "Balancing Authority Operations Coordination Agreement between Wisconsin Electric Power Company and PJM Interconnection, L.L.C." (July 20, 2013) <http://www.pjm.com/~/media/documents/agreements/balancing-authority-operations-coordination-agreement.ashx>.

77 See "Northeastern ISO/RTO Planning Coordination Protocol" (December 8, 2004) <http://www.pjm.com/~/media/documents/agreements/northeastern-iso-rto-planning-coordination-protocol.ashx>.

78 See *PJM Interconnection, L.L.C*, Docket No. ER10-2710-000 (September 17, 2010).

79 The Progress Energy Carolinas (PEC) LMP is defined as the Carolina Power and Light (East) (CPLE) pricing point.

point than they would have if they were to have received the SouthIMP pricing point. The difference between the LMP under these agreements and PJM's SouthEXP LMP ranged from -$2.36 with NCMPA to $1.35 with Duke. This means that under the specific interface pricing agreements transactions settling at the Duke interface price would pay, on average, $1.35 more for exporting energy from PJM than they would have if they were to pay the SouthEXP pricing point. In 2018, market participants paid $7.4 million more for exporting energy using this pricing point than they would have if they were to have paid the SouthEXP pricing point.

Table 9-36 Real-time LMP comparison for Duke, PEC and NCMPA: 2018

	Import LMP	Export LMP	SOUTHIMP	SOUTHEXP	Difference IMP LMP - SOUTHIMP	Difference EXP LMP - SOUTHEXP
Duke	$33.09	$33.77	$32.69	$32.65	$0.40	$1.12
PEC	$53.42	$37.54	$47.42	$36.20	$6.00	$1.35
NCMPA	$29.63	$40.89	$29.12	$43.25	$0.51	($2.36)

Table 9-37 Day-ahead LMP comparison for Duke, PEC and NCMPA: 2018

	Import LMP	Export LMP	SOUTHIMP	SOUTHEXP	Difference IMP LMP - SOUTHIMP	Difference EXP LMP - SOUTHEXP
Duke	$38.12	$37.96	$36.88	$34.96	$1.24	$3.00
PEC	$33.34	$46.44	$32.42	$40.32	$0.92	$6.12
NCMPA	$33.58	$33.41	$31.81	$32.52	$1.77	$0.89

Table 9-37 shows the day-ahead LMP calculated per the PJM/DEP JOA and the high/low pricing method used by Duke and NCMPA for 2018. The values shown in Table 9-37 are the average LMP over only the hours in 2018 where interchange transactions settled at those pricing points. The difference between the LMP under these agreements and PJM's SouthIMP LMP ranged from $0.92 with PEC to $1.77 with NCMPA. This means that under the specific interface pricing agreements, transactions settling at the NCMPA interface price would receive, on average, $1.77 more for importing energy into PJM than if they were to receive the SouthIMP pricing point. In 2018, market participants received $1.8 million more for importing energy using this pricing point than they would have if they were to have received the SouthIMP pricing point. The difference between the LMP under these agreements and PJM's SouthEXP LMP ranged from $0.89 with NCMPA to $6.12 with PEC. This means that under the specific interface pricing agreements, transactions settling at the PEC interface price would pay, on average, $6.12 more for exporting energy from PJM than if they were to pay the SouthEXP pricing point. In 2018, market participants paid $1.9 million more for exporting energy using this pricing point than they would have if they were to have paid the SouthEXP pricing point.

It is not clear that agreements between PJM and neighboring external entities, in which those entities receive some of the benefits of the PJM LMP market without either integrating into an LMP market or applying LMP internally, are in the best interest of PJM's market participants. In the case of the DEP JOA for example, the merger between Progress and Duke has resulted in a single, combined entity where one part of that entity (Duke Energy Progress) is engaged in congestion management with PJM while the other part of the entity (Duke) is not.

Other Agreements with Bordering Areas

Consolidated Edison Company of New York, Inc. (Con Edison) Wheeling Contracts

To help meet the demand for power in New York City, Con Edison uses electricity generated in upstate New York and wheeled through New Jersey on lines controlled by PJM.[80] The Con Edison contracts governing the New Jersey path evolved during the 1970s. This wheeled power creates loop flow across the PJM system and resulted in a Commission approved operating protocol.[81] The Con Edison protocol modeled a fixed MW level flowing from NYISO to PJM over the JK (Ramapo - Waldwick) Interface, and from PJM to NYISO over the ABC (Hudson - Farragut and Linden - Goethals) Interface (Figure 9-12).

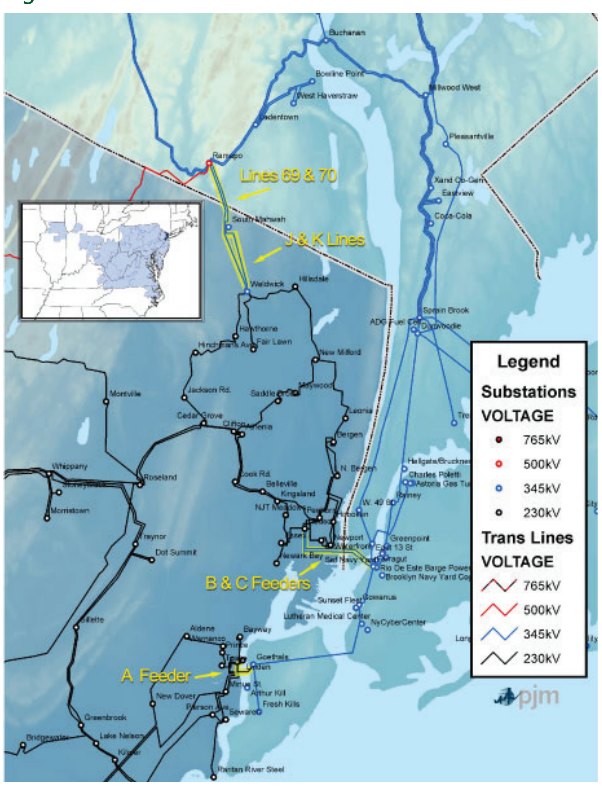
In 2014, cost allocations for RTEP projects included the Bergen-Linden Corridor (BLC) project. Using the solution-based DFAX cost allocation method, Con Edison's share of the BLC's estimated costs was $720 million. On April 28, 2016, to avoid its share of the cost allocation, Con Edison announced its intent to terminate its 1,000 MW long-term firm point-to-point transmission service, effective May 1, 2017. Upon

80 See the *2018 State of the Market Report for PJM*, Section 4 – "Energy Market Uplift" for the operating reserve credits paid to maintain the power flow established in the Con Edison wheeling contracts.

81 See the *2012 State of the Market Report for PJM*, Volume 2, Section 8, "Interchange Transactions," for a more detailed discussion.

termination of the transmission reservation, the Con Edison protocol would also be terminated. On October 4, 2016, the NYISO and PJM issued a white paper to begin discussions for developing alternative designs for using the ABC and JK interfaces upon expiration of the Con Edison protocol effective May, 1, 2017.[82] The white paper proposal included modifications to the existing PJM-NY AC Proxy Bus definition to include the JK and ABC lines and the inclusion of the JK and ABC lines in the market-to-market PAR coordination process. The proposal also includes provisions for determining the target flows over the JK and ABC interfaces. The proposed target flows will be based on a static interchange percentage and will continue to include a percentage of the Rockland Electric Company (RECO) load. The PJM and NYISO proposal also includes an operational base flow (OBF) of 400 MW from NYISO to PJM over the JK Interface and 400 MW from PJM to NYISO over the ABC Interface. On May 1, 2017, the Con Edison protocol was terminated and the new protocol, as described in the December 19, 2016, "*Con Ed/PSEG Wheel Replacement Proposal*" was implemented.[83]

Figure 9-12 Con Edison Protocol



82 See "*Con Ed/PSEG Wheel Replacement Proposal*" (December 19, 2016) which can be accessed at: <http://www.pjm.com/~/media/library/reports-notices/special-reports/20161004-coned-pseg-wheel-replacement-proposal.ashx>.

83 See "*Con Ed/PSEG Wheel Replacement Proposal*" (December 19, 2016) which can be accessed at: <http://www.pjm.com/~/media/library/reports-notices/special-reports/20161004-coned-pseg-wheel-replacement-proposal.ashx>.

Interchange Transaction Issues

Hudson Transmission Partners (HTP) and Linden VFT Requests to Convert Firm Transmission Withdrawal Rights (FTWR) to NonFirm Transmission Withdrawal Rights (NFTWR)

In 2014, cost allocations for RTEP projects included the Bergen-Linden Corridor (BLC) project. Using the solution-based DFAX cost allocation method, PJM initially allocated BLC's estimated costs: $720 million to Con Edison; $103 million to HTP; $10 million to Linden VFT; no costs to Neptune; and $88 million to PSEG. To avoid its share of the cost allocation, Con Edison elected to terminate its 1,000 MW of long-term firm transmission service (the Con Ed Wheel) effective May 1, 2017. PJM reallocated the costs: $634 million to HTP; $132 million to Linden VFT; and the remaining $128 million to PSEG. The Commission denied complaints about the cost allocation, ruling that PJM applied the Commission accepted regional cost allocation method.[84]

In June 2017, HTP and Linden separately initiated the process to amend their interconnection service agreements to reflect the conversion of FTWRs to NFTWRs in an effort to avoid paying their allocated share of the RTEP cost allocations. On June 2, 2017, HTP sent a letter to PJM and PSEG requesting that their original Interconnection Service Agreement (ISA) be amended to reflect the conversion of their 320 MW of FTWRs to NFTWRs. On June 22, 2017, PSEG notified PJM and HTP that it did not agree to the ISA amendment. Because PSEG did not agree to the amendment to the ISA, HTP requested that PJM file an unexecuted amended interconnection service agreement with the Commission to convert their FTWRs to NFTWRs. Similarly, at the request of Linden VFT, PJM also filed an unexecuted amended ISA to convert their FTWRs to NFTWRs.[85] On September 8, 2017, the Commission rejected the amended ISAs and instituted a proceeding "to examine the justness and reasonableness of HTP being unable to convert its Firm Transmission Withdrawal Rights to Non-Firm Transmission Withdrawal Rights." On December 15, 2017, the Commission found that the exiting HTP and

84 155 FERC ¶ 61,089 (2016), *reh'g pending*. With rehearing pending, in light of subsequent developments, including service cancellations intended to avoid RTEP cost allocations, the Commission established settlement proceedings to consider settlement of this proceeding and related cost allocation proceedings. 164 FERC ¶ 61,034 (2018).

85 See *PJM Interconnection, L.L.C*, Docket No. ER17-2267-000 (August 9, 2017).

Linden ISA's are unjust and unreasonable insofar as they do not permit HTP and Linden to convert their FTWRs to NFTWRs and ordered PJM to amend the existing ISAs to reflect the conversion of FTWRs to NFTWRs.[86] [87] On January 19, 2018, PJM filed amended Schedule 12 Appendix and Appendix A revisions reflecting the Commissions orders eliminating the Linden and HTP cost responsibility assignments for RTEP projects with an effective date of January 1, 2018.[88]

Linden requested, and obtained, PJM long-term firm transmission through the long-term firm queue. PJM's Initial Study Long-Term Firm Transmission Service notes:

> … For the purpose of this study, and as requested by the Customer, PJM assumed FERC approval to amend the pre-existing Linden VFT Interconnection Service Agreements (Queue # U2-077 and W1-001) and resulting termination of the associated firm rights.

Linden requested that PJM provide an initial study with the assumption that FERC approves the termination of their FTWRs. Linden VFT expects to maintain the ability to export capacity to NYISO from PJM with the same level of transmission service they currently have under the FTWR construct while avoiding an RTEP cost allocation. Linden VFT has obtained assurance from NYISO that NFTWRs in conjunction with firm point to point transmission service from PJM to the Linden VFT point of delivery, will allow Linden VFT to continue to export capacity from PJM to NYISO exactly as they did with FTWRs.[89]

HTP has, to date, only requested conversion of its FTWRs to NFTWRs. Neptune was not allocated any RTEP costs and has not requested a change in service.

The claim that Linden and/or HTP could use NFTWRs in conjunction with firm point to point transmission to continue to export capacity from PJM to NYISO while avoiding RTEP costs is not correct.

Section 232.2 of the OATT states (emphasis added):

> … A Transmission Interconnection Customer that is granted Firm Transmission Withdrawal Rights <u>and/or transmission customers that have a Point of Delivery at the Border of PJM where the Transmission System interconnects with the Merchant D.C. Transmission Facilities may be responsible for a reasonable allocation of transmission upgrade costs added to the Regional Transmission Expansion Plan after such Transmission Interconnection Customer's Queue Position is established, in accordance with Section 3E and Schedule 12 of the Tariff…</u>

Section 232.2 of the OATT explicitly requires the same RTEP cost allocation when a transmission customer has FTWRs and when a transmission customer has "a Point of Delivery at the Border of PJM where the Transmission System interconnects with the Merchant D.C. Transmission Facilities." That is the situation here. Linden is structured as a controllable AC line which is functionally the same as a DC tie line. Identical treatment of RTEP costs is appropriate because the service is the same. Linden, if it relinquishes its FTWRs and instead uses firm point to point transmission service from PJM to the Linden VFT point of delivery and NFTWRs across the Linden VFT Line, would have the same service before and after the change. These two methods would be appropriately treated the same under Section 232.2, and HTP, if it follows Linden VFT's approach also would be treated the same.

With the conversion of HTP's and Linden's FTWRs to NFTWRs, any acquisition of long-term firm point to point transmission service from PJM to the point of interconnection with their DC tie line, HTP and/or Linden should continue to be assigned a portion of the RTEP cost responsibilities. But such assignment requires modification to Schedule 12 of the OATT to include the options defined in Section 232.2.[90] Once Schedule 12 is modified, HTP and/or Linden would become eligible to export capacity from PJM to the NYISO over their DC tie lines. Section 232.2 of the PJM Tariff combined with the NYISO deliverability requirements for capacity imports makes this explicit.

86 161 FERC ¶ 62,242 (2017).

87 161 FERC ¶ 62,264 (2017).

88 See *PJM Interconnection, L.L.C.*, Docket No. ER18-680-000 (January 19, 2018).

89 See *Discussion of UDR Deliverability Requirements* (September 18, 2017) at: <https://www.nyiso.com/documents/20142/1406254/UDR%20Deliverability%20Requirements.pdf/09988c85-84d5-f911-42ba-8c578695128d>.

90 PJM files cost responsibility assignments for transmission projects that are selected in the PJM Regional Transmission Expansion Plan (RTEP) for purposes of cost allocations in accordance with Schedule 12 of the OATT.

It would not be reasonable or consistent with economic logic to permit HTP and/or Linden to retain the same capacity export service with a different name and avoid an allocation of RTEP costs.

PJM Transmission Loading Relief Procedures (TLRs)

TLRs are called to control flows on electrical facilities when economic redispatch cannot solve overloads on those facilities. TLRs are called to control flows related to external balancing authorities, as redispatch within an LMP market can generally resolve overloads on internal transmission facilities.

The number of PJM issued TLRs of level 3a or higher decreased from six in 2017 to five in 2018.[91] The number of different flowgates for which PJM declared a TLR 3a or higher increased from three in 2017 to four in 2018. The total MWh of transactions curtailed decreased by 53.5 percent from 13,059 MWh in 2017 to 6,066 MWh in 2018.

The number of MISO issued TLRs of level 3a or higher decreased from 75 in 2017 to 56 in 2018. The number of different flowgates for which MISO declared a TLR 3a decreased from 25 in 2017 to 24 in 2018. The total MWh of transaction curtailments decreased by 22.4 percent from 72,069 MWh in 2017 to 55,940 MWh in 2018.

The number of NYISO issued TLRs of level 3a or higher increased from one in 2017 to two in 2018. The number of different flowgates for which NYISO declared a TLR 3a or higher increased from one in 2017 to two in 2018. The total MWh of transaction curtailments increased by 100.0 percent from 0 MWh in 2017 to 6,194 MWh in 2018.

Table 9-38 PJM, MISO, and NYISO TLR procedures: 2015 through 2018

	Number of TLRs Level 3 and Higher			Number of Unique Flowgates That Experienced TLRs			Curtailment Volume (MWh)		
Month	PJM	MISO	NYISO	PJM	MISO	NYISO	PJM	MISO	NYISO
Jan-15	2	8	1	1	4	1	7,293	626	2,261
Feb-15	6	11	2	2	6	1	37,222	9,173	331
Mar-15	8	0	1	3	0	1	14,704	0	435
Apr-15	2	6	0	2	3	0	1,033	23,518	0
May-15	1	8	0	1	2	0	961	12,048	0
Jun-15	1	20	0	1	4	0	205	42,063	0
Jul-15	2	10	0	2	4	0	1,360	9,796	0
Aug-15	0	9	0	0	3	0	0	7,041	0
Sep-15	0	6	0	0	4	0	0	5,789	0
Oct-15	0	4	0	0	4	0	0	4,212	0
Nov-15	0	2	0	0	2	0	0	1,797	0
Dec-15	0	4	0	0	1	0	0	875	0
Jan-16	6	0	0	1	0	0	83,752	0	0
Feb-16	2	0	0	1	0	0	23,096	0	0
Mar-16	0	5	0	0	3	0	0	6,556	0
Apr-16	0	6	0	0	2	0	0	2,034	0
May-16	0	6	0	0	4	0	0	5,360	0
Jun-16	0	5	1	0	2	1	0	18,121	217
Jul-16	0	18	0	0	8	0	0	38,815	0
Aug-16	0	16	0	0	3	0	0	30,181	0
Sep-16	0	8	0	0	4	0	0	19,394	0
Oct-16	0	3	0	0	2	0	0	1,702	0
Nov-16	0	9	0	0	3	0	0	5,622	0
Dec-16	1	1	0	1	1	0	443	0	0
Jan-17	3	1	0	1	1	0	6,140	255	0
Feb-17	0	8	0	0	2	0	0	10,566	0
Mar-17	0	9	0	0	4	0	0	7,954	0
Apr-17	0	10	0	0	7	0	0	16,422	0
May-17	0	11	0	0	8	0	0	7,292	0
Jun-17	0	13	0	0	6	0	0	8,576	0
Jul-17	0	0	1	0	0	1	0	0	0
Aug-17	0	3	0	0	2	0	0	2,449	0
Sep-17	0	4	0	0	3	0	0	6,439	0
Oct-17	1	12	0	1	7	0	763	9,089	0
Nov-17	0	2	0	0	2	0	0	806	0
Dec-17	2	2	0	2	2	0	6,156	2,221	0
Jan-18	1	7	1	1	4	1	3,283	9,198	1,428
Feb-18	0	0	0	0	0	0	0	0	0
Mar-18	0	2	0	0	2	0	0	1,185	0
Apr-18	2	3	0	1	3	0	656	1,180	0
May-18	1	11	0	1	7	0	1,893	3,373	0
Jun-18	0	12	0	0	5	0	0	9,643	0
Jul-18	0	1	0	0	1	0	0	134	0
Aug-18	0	6	0	0	3	0	0	7,852	0
Sep-18	0	5	1	0	3	1	0	3,203	4,766
Oct-18	0	5	0	0	4	0	0	6,474	0
Nov-18	0	1	0	0	1	0	0	440	0
Dec-18	1	3	0	1	3	0	234	13,258	0

91 TLR Level 3a is the first level of TLR that results in the curtailment of transactions. See the *2018 State of the Market Report for PJM*, Volume 2, Appendix E, "Interchange Transactions," for a more complete discussion of TLR levels.

Table 9-39 Number of TLRs by TLR level by reliability coordinator: 2018[92]

Year	Reliability Coordinator	3a	3b	4	5a	5b	6	Total
2018	MISO	22	5	0	11	18	0	56
	NYIS	1	1	0	0	0	0	2
	ONT	10	0	0	0	0	0	10
	PJM	2	1	0	0	2	0	5
	SOCO	0	1	0	0	0	0	1
	SWPP	36	8	0	52	21	0	117
	TVA	10	34	0	9	6	0	59
	VACS	2	8	0	0	0	0	10
Total		83	58	0	72	47	0	260

Up To Congestion

The original purpose of up to congestion transactions (UTC) was to allow market participants to submit a maximum congestion charge, up to $25 per MWh, they were willing to pay on an import, export or wheel through transaction in the Day-Ahead Energy Market. This product was offered as a tool for market participants to limit their congestion exposure on scheduled transactions in the Real-Time Energy Market.[93]

Following the elimination of the requirement to procure and pay for transmission service for up to congestion transactions effective September 17, 2010, the volume of transactions increased dramatically.

Up to congestion transactions affect the day-ahead dispatch and unit commitment. Despite that, up to congestion transactions do not pay operating reserves charges. Up to congestion transactions also negatively affect FTR funding.[94]

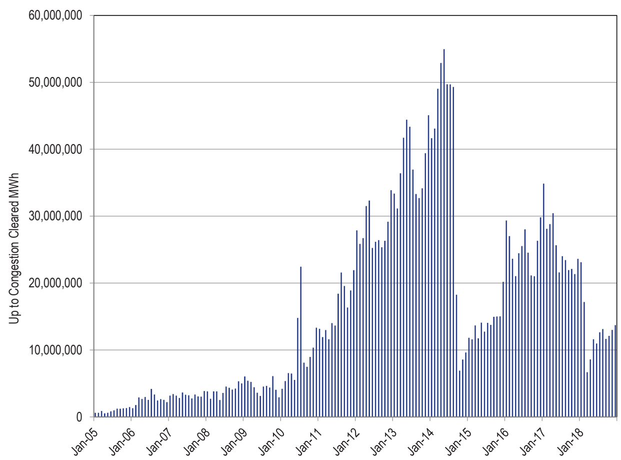
On August 29, 2014, FERC issued an order which created an obligation for UTCs to pay any uplift determined to be appropriate based on Commission review, effective September 8, 2014.[95]

As a result of the potential requirement to pay uplift charges and the uncertainty about the level of the required uplift charges, market participants reduced up to congestion trading effective September 8, 2014. There was an increase in up to congestion volume starting in December 2015, coincident with the expiration of the fifteen month limit on the payment of prior uplift charges (Figure 9-13). Section 206(b) of the Federal Power Act states that "...the Commission may order refunds of any amounts paid, for the period subsequent to the refund effective date through a date fifteen months after such refund effective date..."[96]

On February 20, 2018, FERC issued an order limiting the eligible bidding points for up to congestion transactions to hubs, residual metered load and interfaces.[97] As a result, market participants reduced up to congestion trading effective February 22, 2018.

The average number of up to congestion bids submitted in the Day-Ahead Energy Market decreased by 53.4 percent, from 138,489 bids per day in 2017 to 64,574 bids per day in 2018. The average cleared volume of up to congestion bids submitted in the Day-Ahead Energy Market decreased by 49.5 percent, from 838,258 MWh per day in 2017, to 422,981 MWh per day in 2018.

Figure 9-13 Monthly up to congestion cleared bids in MWh: 2005 through 2018



92 Southern Company Services, Inc. (SOCO) is the reliability coordinator covering a portion of Mississippi, Alabama, Florida and Georgia. Southwest Power Pool (SWPP) is the reliability coordinator for SPP. VACAR-South (VACS) is the reliability coordinator covering a portion of North Carolina and South Carolina.

93 See the *2012 State of the Market Report for PJM*, Volume 2, Section 8, "Interchange Transactions," for a more detailed discussion.

94 See the *2018 State of the Market Report for PJM*, Section 13: FTRs and ARRs, "FTR Forfeitures" for more information on up to congestion transaction impacts on FTRs.

95 148 FERC ¶ 61,144 (2014).

96 16 U.S.C. § 824e.

97 162 FERC ¶ 61,139 (2018).

Table 9-40 Monthly volume of cleared and submitted up to congestion bids: 2017 through 2018[98]

	Bid MW					Bid Volume				
Month	Import	Export	Wheel	Internal	Total	Import	Export	Wheel	Internal	Total
Jan-17	12,071,248	10,779,934	1,022,748	122,301,537	146,175,467	503,193	359,899	34,470	6,725,774	7,623,336
Feb-17	11,420,648	8,942,116	608,065	118,800,901	139,771,730	394,062	268,571	27,086	4,894,155	5,583,874
Mar-17	9,158,336	9,968,026	595,492	102,176,604	121,898,458	284,402	289,574	24,835	4,046,536	4,645,347
Apr-17	8,427,340	9,544,151	576,134	91,517,521	110,065,146	243,246	286,654	28,526	3,777,591	4,336,017
May-17	6,914,185	5,793,561	532,000	73,575,991	86,815,737	210,223	210,292	21,746	3,246,035	3,688,296
Jun-17	5,490,865	6,038,899	632,947	68,528,243	80,690,953	194,713	191,222	20,606	3,077,217	3,483,758
Jul-17	6,613,969	6,050,326	639,026	74,941,744	88,245,065	203,947	198,230	19,463	3,378,819	3,800,459
Aug-17	6,749,590	6,674,135	718,858	77,129,276	91,271,858	191,589	188,708	11,951	3,374,088	3,766,336
Sep-17	6,762,933	6,905,161	652,672	72,767,743	87,088,509	172,092	169,393	11,818	2,831,072	3,184,375
Oct-17	6,477,119	7,030,028	638,955	73,263,143	87,409,245	182,695	210,191	11,980	3,125,553	3,530,419
Nov-17	6,961,973	6,561,240	642,567	65,378,670	79,544,452	217,415	195,059	13,324	2,947,507	3,373,305
Dec-17	7,586,123	6,516,890	711,886	69,995,034	84,809,933	231,328	175,164	15,744	3,110,890	3,533,126
Jan-18	6,693,483	7,662,968	964,569	77,009,951	92,330,971	248,760	203,232	17,467	4,374,531	4,843,990
Feb-18	5,221,484	6,409,422	819,944	51,178,869	63,629,719	178,507	175,403	18,605	2,787,881	3,160,396
Mar-18	7,198,570	2,684,392	1,641,523	9,285,316	20,809,801	405,718	170,727	76,172	810,443	1,463,060
Apr-18	10,593,924	3,145,340	2,567,203	15,365,820	31,672,285	479,450	120,650	68,477	771,799	1,440,376
May-18	11,309,503	3,914,473	2,621,845	19,453,217	37,299,037	517,327	119,707	53,586	886,577	1,577,197
Jun-18	10,165,362	3,767,069	2,613,562	16,723,385	33,269,378	399,986	87,810	40,434	763,388	1,291,618
Jul-18	9,895,083	2,011,081	2,397,682	22,207,892	36,511,737	488,146	129,135	48,678	1,183,510	1,849,469
Aug-18	13,524,492	1,838,512	3,071,033	21,055,373	39,489,410	561,803	100,964	46,574	1,014,352	1,723,693
Sep-18	10,503,480	4,148,333	3,322,123	20,309,280	38,283,216	445,037	94,821	51,019	812,439	1,403,316
Oct-18	10,977,336	4,063,127	2,832,812	19,223,993	37,097,269	435,432	133,048	50,325	954,489	1,573,294
Nov-18	11,903,568	4,093,631	2,752,372	23,118,009	41,867,580	474,565	96,770	44,125	950,934	1,566,394
Dec-18	8,557,434	3,709,128	2,408,350	26,836,764	41,511,676	276,497	103,963	47,479	1,248,751	1,676,690
TOTAL	211,178,047	138,251,940	35,984,368	1,332,144,277	1,717,558,631	7,940,133	4,279,187	804,490	61,094,331	74,118,141

	Cleared MW					Cleared Volume				
Month	Import	Export	Wheel	Internal	Total	Import	Export	Wheel	Internal	Total
Jan-17	3,478,967	2,446,235	235,641	28,699,881	34,860,725	153,756	106,883	6,710	2,387,196	2,654,545
Feb-17	2,020,772	1,860,138	88,621	24,147,889	28,117,419	91,586	76,129	5,506	1,648,658	1,821,879
Mar-17	2,106,568	1,736,786	147,294	24,822,836	28,813,485	87,599	86,494	5,157	1,509,134	1,688,384
Apr-17	2,507,486	2,351,550	176,621	25,401,805	30,437,462	81,365	93,895	6,981	1,435,787	1,618,028
May-17	1,716,363	1,564,608	126,693	22,243,327	25,650,992	70,481	70,024	5,163	1,314,020	1,459,688
Jun-17	1,572,832	1,428,776	135,513	18,460,280	21,597,400	62,478	61,569	3,893	1,168,823	1,296,763
Jul-17	1,546,229	1,546,263	113,165	20,816,061	24,021,719	60,457	68,847	3,371	1,262,370	1,395,045
Aug-17	1,177,158	1,746,210	100,492	20,420,033	23,443,893	58,192	75,898	3,032	1,299,202	1,436,324
Sep-17	1,632,026	1,379,580	102,737	18,835,214	21,949,558	66,178	54,143	3,205	1,129,589	1,253,115
Oct-17	1,482,374	1,616,248	139,924	18,871,489	22,110,035	65,586	85,126	4,400	1,286,807	1,441,919
Nov-17	1,455,401	1,549,254	136,025	18,205,565	21,346,245	65,423	76,099	5,231	1,187,848	1,334,601
Dec-17	1,698,478	1,484,766	149,340	20,282,749	23,615,331	61,703	66,518	5,843	1,187,420	1,321,484
Jan-18	1,467,644	1,595,640	259,173	19,790,703	23,113,162	72,327	67,941	6,648	1,470,535	1,617,451
Feb-18	1,312,958	1,559,790	223,702	14,068,590	17,165,039	65,952	70,121	8,429	1,103,722	1,248,224
Mar-18	2,228,586	819,477	399,161	3,232,145	6,679,368	145,743	55,930	24,612	318,655	544,940
Apr-18	2,951,060	728,157	352,423	4,557,862	8,589,502	191,558	40,919	19,629	379,069	631,175
May-18	3,891,624	1,073,540	638,477	5,996,981	11,600,622	215,222	48,034	21,288	381,157	665,701
Jun-18	3,473,835	1,218,987	769,637	5,500,944	10,963,403	172,868	43,078	17,529	361,764	595,239
Jul-18	3,756,816	616,857	691,554	7,588,929	12,654,157	234,818	51,413	21,034	512,342	819,607
Aug-18	4,449,172	759,823	929,122	6,999,351	13,137,468	248,048	43,884	20,619	429,365	741,916
Sep-18	3,382,522	1,130,568	813,755	6,322,535	11,649,379	189,297	37,680	17,342	372,208	616,527
Oct-18	3,372,457	1,254,074	665,212	6,823,263	12,115,006	182,064	56,691	18,422	441,069	698,246
Nov-18	3,614,335	1,206,420	657,895	7,518,666	12,997,315	210,762	54,479	21,050	460,142	746,433
Dec-18	2,988,179	1,139,101	674,573	8,921,740	13,723,593	126,333	60,064	20,146	650,430	856,973
TOTAL	59,283,840	33,812,847	8,726,750	358,528,838	460,352,276	2,979,796	1,551,859	275,240	23,697,312	28,504,207

In 2018, the cleared MW volume of up to congestion transactions was comprised of 23.9 percent imports, 8.5 percent exports, 4.6 percent wheeling transactions and 63.0 percent internal transactions. Less than 0.1 percent of the up to congestion transactions had matching real-time energy market transactions.

98 See the *2016 State of the Market Report for PJM*, Volume 2, Appendix E, "Interchange Transactions," for the monthly volume of cleared and submitted up to congestion bids: 2009 through 2016.

Sham Scheduling

Sham scheduling refers to a scheduling method under which a market participant breaks a single transaction, from generation balancing authority (source) to load balancing authority (sink), into multiple segments. Sham scheduling hides the actual source of generation from the load balancing authority. When unable to identify the source of the energy, the load balancing authority cannot see how the power will flow to the load, which can create loop flows and result in inaccurate pricing for transactions.

For example, if the generation balancing authority (source) is NYISO, and the load balancing authority (sink) is PJM, the transaction would be priced, in the PJM energy market, at the PJM/NYIS Interface regardless of the submitted path. However, if a market participant were to break the transaction into multiple segments, one on the NYIS-ONT path, and a second segment on the ONT-MISO-PJM path, the market participant would conceal the true source (NYISO) from PJM, and PJM would price the transaction as if its source were Ontario (the ONT interface price).

Sham scheduling can also be achieved by submitting a transaction that is in the opposite direction of a portion of a larger transaction schedule.

For example, market participants can submit one transaction with multiple segments among balancing authorities and another transaction which offsets all or part of a segment of the first transaction. If a market participant submits two separate transactions, one on the ONT-MISO-PJM path, and a second on the PJM-MISO path, the result of these transactions would be a net scheduled transaction from ONT to MISO, as the MISO-PJM segment of the first transaction is offset by the PJM-MISO transaction. In this example, PJM is not required to raise or lower generation as a result of these transactions, as they would for an import or an export, and there are no associated power flows across PJM. Nonetheless, the market participant is paid the price difference between the PJM/ONT interface pricing point and the PJM/MISO interface pricing point. The market participant would be paid the PJM/ONT interface pricing point for the first transaction (ONT to PJM import) and the market participant would pay the PJM/MISO interface pricing point for the second transaction (PJM to MISO export). If the PJM/ONT interface price were higher than the PJM/MISO interface price, the market participant would be paid a net profit from the PJM market even though there was no impact on PJM operations.

The MMU recommends that PJM implement rules to prevent sham scheduling. The MMU recommends that PJM apply after the fact market settlement adjustments to identified sham scheduling segments to ensure that market participants cannot benefit from sham scheduling.

Elimination of Ontario Interface Pricing Point

The PJM/IMO interface pricing point (Ontario) was created to reflect the fact that transactions that originate or sink in the IESO balancing authority create actual energy flows that are split between the MISO and NYISO interface pricing points. PJM created the PJM/IMO interface pricing point to reflect the actual power flows across both the MISO/PJM and NYISO/PJM interfaces. The IMO does not have physical ties with PJM because it is not contiguous.

Prior to June 1, 2015, the PJM/IMO interface pricing point was defined as the LMP at the IESO Bruce bus. The LMP at the Bruce bus includes a congestion and loss component across the MISO and NYISO balancing authorities.

The noncontiguous nature of the PJM/IMO interface pricing point creates opportunities for market participants to engage in sham scheduling activities. For example, a market participant can use two separate transactions to create a flow from Ontario to MISO. In this example, the market participant uses the PJM energy market as a temporary generation and load point by first submitting a wheeling transaction from Ontario, through MISO and into PJM, then by submitting a second transaction from PJM to MISO. These two transactions, combined, create an actual flow along the Ontario/MISO Interface. Through sham scheduling, the market participant receives settlements from PJM when no changes in generation occur. This activity is similar to that observed when PJM had a Southwest and Southeast interface pricing point. During that time, market participants would use the PJM spot market as a temporary load and generation point to wheel transactions through the PJM energy market.

This was done to take advantage of the price differences between the interfaces without providing the market benefits of congestion relief.

A new PJM/IMO interface price method was implemented on June 1, 2015. The new method uses a dynamic weighting of the PJM/MISO interface price and the PJM/NYIS interface price, based on the performance of the Michigan-Ontario PARs. When the absolute value of the actual flows on the PARs are greater than or equal to the absolute value of the scheduled flows on the PARs, and the scheduled and actual flows are in the same direction, the PJM/IMO interface price will be equal to the PJM/MISO interface price (i.e. 100 percent weighting on the PJM/MISO Interface). When actual flows on the PARs are in the opposite direction of the scheduled flows on the PARs, the PJM/IMO interface price will be equal to the PJM/NYIS interface price (i.e. 100 percent weighting on the PJM/NYIS Interface). When the absolute value of the actual flows on the PARs are less than or equal to the absolute value of the scheduled flows on the PARs, and the scheduled and actual flows are in the same direction, the PJM/IMO interface price will be a combination to the PJM/MISO interface price and the PJM/NYIS interface price. In this case the weightings of the PJM/MISO and PJM/NYIS interface prices are determined based on the scheduled and actual flows. For example, in a given interval, the scheduled flow on the Michigan-Ontario PARs is 1,000 MW, and the actual flow is 800 MW. If in that same interval, the PJM/MISO interface price is $45.00 and the PJM/NYIS interface price $30.00, the PJM/IMO interface price would be calculated with a weighting of 80 percent of the PJM/MISO interface price ($45.00 * 0.8, or $36.00) and 20 percent of the PJM/NYIS interface price ($30.00 * 0.2, or $6.00), for a PJM/IMO interface price of $42.00.[99]

The MMU believes that the new PJM/IMO interface price method is a step in the right direction towards pricing energy that sources or sinks in Ontario based on the path of the actual, physical transfer of energy. The MMU remains concerned about the assumption of PAR operations, and will continue to evaluate the impact of PARs on the scheduled and actual flows and the impacts on the PJM/IMO interface price. The MMU remains concerned about the potential for market participants to continue to engage in sham scheduling activities after the new method is implemented.

The MMU recommends that if the PJM/IMO interface price remains and with PJM's new method in place, that PJM implement additional business rules to remove the incentive to engage in sham scheduling activities using the PJM/IMO interface price. Such rules would prohibit the same market participant from scheduling an export transaction from PJM to any balancing authority while at the same time an import transaction is scheduled to PJM that receives the PJM/IMO interface price. PJM should also prohibit the same market participant from scheduling an import transaction to PJM from any balancing authority while at the same time an export transaction is scheduled from PJM that receives the PJM/IMO interface price.

In 2018, of the 1,536 GWh of the gross scheduled transactions between PJM and IESO, 1,534 GWh (99.9 percent) wheeled through MISO (Table 9-23). The MMU recommends that PJM eliminate the PJM/IMO interface pricing point, and assign the transactions that originate or sink in the IESO balancing authority to the PJM/MISO interface pricing point.[100]

PJM and NYISO Coordinated Interchange Transactions

Coordinated transaction scheduling (CTS) provides the option for market participants to submit intra-hour transactions between the NYISO and PJM that include an interface spread bid on which transactions are evaluated.[101] The evaluation is based on the forward-looking prices as determined by PJM's intermediate term security constrained economic dispatch tool (ITSCED) and the NYISO's real-time commitment (RTC) tool. PJM shares its PJM/NYISO interface price ITSCED results with the NYISO. The NYISO compares the PJM/NYISO interface price with its RTC calculated NYISO/PJM interface price. If the PJM and NYISO interface price spread is greater than the market participant's CTS bid, the transaction is approved. If the PJM and NYISO interface price spread is less than the CTS bid, the transaction is denied.

99 See "IMO Interface Definition Methodology Report," presented to the MIC (February 11, 2015) <http://www.pjm.com/~/media/committees-groups/committees/mic/20150211/20150211-item-08b-imo-interface-definition-methodology-report.ashx>.

100 On October 1, 2013, a sub-group of PJM's Market Implementation Committee started stakeholder discussions to address this inconsistency in market pricing.

101 PJM and the NYISO implemented CTS on November 4, 2014. 146 FERC ¶ 61,096 (2014).

The ITSCED application runs approximately every five minutes and each run produces forecast LMPs for the intervals approximately 30 minutes, 45 minutes, 90 minutes and 135 minutes ahead. Therefore, for each 15 minute interval, the various ITSCED solutions will produce 12 forecasted PJM/NYIS interface prices. To evaluate the accuracy of ITSCED forecasts, the forecasted PJM/NYIS interface price for each 15 minute interval from ITSCED was compared to the actual real-time interface LMP for 2018. Table 9-41 shows that over all 12 forecast ranges, ITSCED predicted the real-time PJM/NYIS interface LMP within the range of $0.00 to $5.00 in 26.1 percent of the intervals. In those intervals, the average price difference between the ITSCED forecasted LMP and the actual real-time LMP was $1.71 per MWh. In 9.7 percent of all intervals, the absolute value of the average price difference between the ITSCED forecasted LMP and the actual real-time interface LMP was greater than $20.00. The average price differences were $61.18 when the price difference was greater than $20.00, and $75.90 when the price difference was greater than -$20.00.

Table 9-41 Differences between forecast and actual PJM/NYIS interface prices: 2018

Range of Price Differences	Percent of All Intervals	Average Price Difference
> $20	3.8%	$61.18
$10 to $20	4.9%	$13.92
$5 to $10	7.2%	$7.13
$0 to $5	26.1%	$1.71
$0 to -$5	40.4%	$1.74
-$5 to -$10	7.3%	$6.98
-$10 to -$20	4.3%	$14.16
< -$20	5.9%	$75.90

Table 9-42 Differences between forecast and actual PJM/NYIS interface prices: 2018

	~ 135 Minutes Prior to Real-Time		~ 90 Minutes Prior to Real-Time		~ 45 Minutes Prior to Real-Time		~ 30 Minutes Prior to Real-Time	
Range of Price Differences	Percent of Intervals	Average Price Difference	Percent of Intervals	Average Price Difference	Percent of Intervals	Average Price Difference	Percent of Intervals	Average Price Difference
> $20	3.2%	$48.56	2.9%	$45.83	3.0%	$53.79	4.5%	$65.90
$10 to $20	5.3%	$14.01	4.6%	$13.79	4.5%	$13.79	5.0%	$13.87
$5 to $10	7.1%	$7.22	7.7%	$7.10	7.3%	$7.05	7.5%	$7.14
$0 to $5	23.2%	$1.78	26.8%	$1.72	28.6%	$1.68	26.8%	$1.69
$0 to -$5	40.5%	$1.92	39.5%	$1.78	39.5%	$1.64	40.1%	$1.65
-$5 to -$10	8.7%	$6.95	7.7%	$6.97	6.6%	$6.98	6.3%	$6.95
-$10 to -$20	5.2%	$14.23	4.3%	$14.19	4.2%	$14.19	3.9%	$14.11
< -$20	6.7%	$90.03	6.5%	$73.98	6.2%	$72.89	5.8%	$75.52

Table 9-42 shows how the accuracy of the ITSCED forecasted LMPs changes as the cases approach real-time. In the final ITSCED results prior to real time, in 66.9 percent of all intervals, the average price difference between the ITSCED forecasted LMP and the actual real-time interface LMP fell within +/- $5.00 of the actual PJM/NYIS interface real-time LMP, compared to 63.7 percent in the 135 minute ahead ITSCED results.

In 10.3 percent of the intervals in the 30 minute ahead forecast, the absolute value of the average price difference between the ITSCED forecasted LMP and the actual real-time interface LMP was greater than $20.00, the average price difference was $65.90 when the price difference was greater than $20.00, and $75.52 when the price difference was greater than -$20.00.

Table 9-43 and Table 9-44 show the monthly differences between forecasted and actual PJM/NYIS interface prices. Analysis of the data on a monthly basis shows that there is a decline in the accuracy of the ITSCED forecast ability during periods of cold and hot weather.

Table 9-43 Monthly Differences between forecast and actual PJM/NYIS interface prices (percent of intervals): 2018

Interval	Range of Price Differences	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	YTD Avg
~ 30 Minutes Prior to Real-Time	> $20	10.4%	0.6%	1.4%	6.5%	8.0%	2.1%	3.7%	4.8%	7.3%	4.3%	3.3%	1.4%	4.5%
	$10 to $20	3.2%	1.0%	3.4%	9.2%	10.8%	2.6%	6.4%	4.0%	4.7%	7.8%	5.4%	1.8%	5.0%
	$5 to $10	3.0%	3.4%	6.2%	14.2%	15.7%	5.7%	7.1%	7.2%	6.2%	11.0%	6.8%	3.2%	7.5%
	$0 to $5	12.9%	26.7%	35.7%	28.4%	33.6%	33.5%	21.7%	20.3%	21.6%	34.1%	30.1%	23.6%	26.8%
	$0 to -$5	32.5%	56.8%	39.5%	24.6%	20.5%	45.3%	47.1%	48.5%	45.1%	29.8%	38.6%	53.1%	40.1%
	-$5 to -$10	6.6%	6.5%	5.6%	6.7%	4.2%	5.0%	5.6%	7.8%	8.0%	5.6%	6.1%	8.5%	6.3%
	-$10 to -$20	7.3%	2.7%	4.0%	4.6%	3.1%	2.4%	3.3%	3.3%	3.7%	3.6%	4.5%	4.4%	3.9%
	< -$20	24.2%	2.4%	4.2%	5.8%	4.1%	3.5%	5.0%	4.0%	3.4%	3.9%	5.2%	4.0%	5.8%
Interval	Range of Price Differences	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	YTD Avg
~ 45 Minutes Prior to Real-Time	> $20	9.1%	0.2%	0.8%	3.4%	4.0%	1.3%	2.6%	3.3%	5.1%	3.6%	1.8%	0.9%	3.0%
	$10 to $20	3.5%	0.5%	2.3%	7.6%	10.0%	2.2%	5.1%	4.6%	4.6%	7.7%	4.1%	1.7%	4.5%
	$5 to $10	3.4%	3.1%	4.8%	13.4%	16.0%	5.2%	7.5%	6.8%	7.0%	10.7%	6.1%	2.9%	7.3%
	$0 to $5	15.2%	29.3%	38.5%	31.8%	34.5%	37.1%	25.5%	23.0%	24.1%	33.2%	29.3%	22.2%	28.6%
	$0 to -$5	31.2%	55.0%	38.9%	24.8%	21.5%	42.1%	45.7%	48.6%	44.0%	30.3%	39.5%	54.2%	39.5%
	-$5 to -$10	7.1%	6.8%	5.8%	8.1%	5.4%	5.6%	4.5%	6.1%	7.7%	6.2%	7.6%	8.8%	6.6%
	-$10 to -$20	6.8%	2.5%	4.1%	4.4%	3.5%	2.6%	3.8%	3.4%	3.8%	4.0%	5.8%	5.3%	4.2%
	< -$20	23.8%	2.6%	4.7%	6.5%	4.9%	4.0%	5.3%	4.3%	3.8%	4.3%	5.8%	4.1%	6.2%
Interval	Range of Price Differences	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	YTD Avg
~ 90 Minutes Prior to Real-Time	> $20	8.5%	0.3%	0.8%	3.2%	3.3%	0.6%	2.2%	3.4%	3.6%	3.5%	3.7%	0.9%	2.9%
	$10 to $20	3.6%	0.4%	3.0%	6.5%	11.0%	2.6%	5.3%	5.1%	5.1%	6.3%	4.1%	1.7%	4.6%
	$5 to $10	3.4%	3.5%	5.2%	13.7%	17.8%	4.9%	8.7%	9.5%	7.8%	8.7%	6.7%	2.8%	7.7%
	$0 to $5	17.4%	31.3%	38.2%	29.7%	29.0%	39.2%	27.3%	23.7%	24.0%	23.2%	23.7%	16.2%	26.8%
	$0 to -$5	27.8%	52.0%	37.0%	26.7%	22.9%	39.0%	42.8%	45.4%	41.8%	40.2%	42.9%	56.4%	39.5%
	-$5 to -$10	8.0%	7.4%	6.6%	8.9%	6.2%	6.8%	4.7%	5.6%	9.0%	9.0%	8.3%	11.8%	7.7%
	-$10 to -$20	5.9%	2.6%	4.3%	4.7%	4.0%	2.7%	3.8%	3.3%	4.4%	4.5%	5.1%	5.9%	4.3%
	< -$20	25.5%	2.5%	4.8%	6.7%	5.9%	4.2%	5.2%	4.1%	4.2%	4.5%	5.5%	4.3%	6.5%
Interval	Range of Price Differences	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	YTD Avg
~ 135 Minutes Prior to Real-Time	> $20	11.6%	0.3%	1.3%	5.8%	4.3%	0.6%	1.9%	3.8%	3.4%	2.8%	1.7%	1.0%	3.2%
	$10 to $20	3.7%	1.2%	4.7%	7.9%	12.4%	2.3%	5.9%	8.2%	5.8%	6.4%	3.5%	1.3%	5.3%
	$5 to $10	3.6%	3.3%	7.6%	12.4%	13.9%	4.9%	8.2%	6.8%	7.7%	8.7%	5.6%	2.4%	7.1%
	$0 to $5	15.4%	28.2%	36.1%	26.7%	23.1%	26.4%	22.1%	17.6%	21.6%	22.3%	22.8%	16.7%	23.2%
	$0 to -$5	29.0%	52.0%	34.0%	27.4%	23.7%	48.1%	45.6%	47.3%	41.2%	40.0%	43.8%	55.2%	40.5%
	-$5 to -$10	6.7%	9.4%	7.0%	8.9%	8.7%	9.0%	6.0%	7.9%	10.0%	9.4%	9.7%	12.4%	8.7%
	-$10 to -$20	6.5%	3.0%	4.6%	4.5%	6.4%	4.1%	4.4%	4.3%	5.8%	5.5%	6.7%	6.7%	5.2%
	< -$20	23.6%	2.7%	4.7%	6.3%	7.5%	4.7%	5.8%	4.1%	4.5%	4.9%	6.2%	4.4%	6.7%

Table 9-44 Monthly differences between forecast and actual PJM/NYIS interface prices (average price difference): 2018

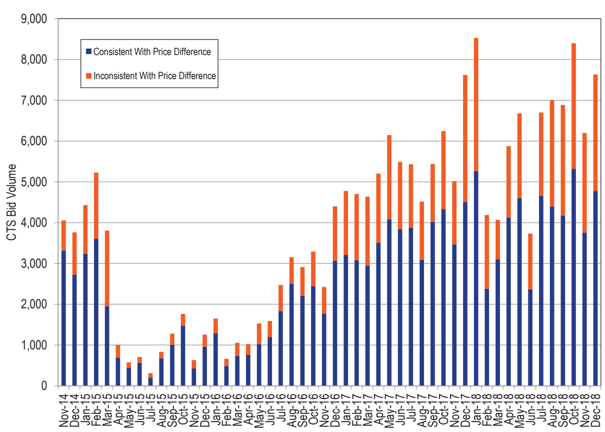
Interval	Range of Price Differences	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	YTD Avg
~ 30 Minutes Prior to Real-Time	> $20	$66.58	$43.75	$35.03	$97.42	$58.66	$52.01	$88.02	$79.59	$72.55	$34.05	$36.32	$46.46	$65.90
	$10 to $20	$14.22	$12.87	$14.02	$13.75	$13.77	$14.13	$14.10	$13.65	$13.99	$13.76	$13.78	$14.58	$13.87
	$5 to $10	$7.07	$6.82	$6.81	$7.25	$7.31	$7.09	$7.13	$7.15	$6.89	$7.23	$7.15	$6.97	$7.14
	$0 to $5	$1.39	$1.37	$1.55	$2.11	$2.20	$1.26	$1.68	$1.95	$1.82	$1.82	$1.61	$1.33	$1.69
	$0 to -$5	$1.54	$1.74	$1.43	$1.90	$1.90	$1.39	$1.46	$1.53	$1.86	$1.79	$1.85	$1.67	$1.65
	-$5 to -$10	$7.17	$6.77	$7.18	$6.99	$7.10	$6.85	$6.78	$6.74	$6.81	$7.08	$7.01	$6.99	$6.95
	-$10 to -$20	$14.25	$13.87	$14.11	$14.24	$13.82	$13.80	$14.15	$14.09	$14.06	$13.83	$14.20	$14.37	$14.11
	< -$20	$91.15	$56.61	$49.97	$60.38	$138.93	$54.12	$62.11	$67.74	$68.04	$53.27	$51.85	$79.09	$75.52
Interval	Range of Price Differences	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	YTD Avg
~ 45 Minutes Prior to Real-Time	> $20	$62.08	$46.37	$26.85	$43.64	$55.62	$51.72	$98.36	$44.64	$51.67	$37.44	$33.83	$50.92	$53.79
	$10 to $20	$14.74	$14.57	$14.15	$13.29	$13.38	$13.38	$13.82	$13.86	$13.84	$13.98	$14.08	$14.14	$13.79
	$5 to $10	$7.15	$6.69	$7.01	$7.22	$7.13	$6.91	$7.12	$6.85	$6.99	$7.08	$7.03	$6.72	$7.05
	$0 to $5	$1.40	$1.44	$1.62	$2.12	$2.10	$1.24	$1.62	$1.85	$1.83	$1.79	$1.65	$1.32	$1.68
	$0 to -$5	$1.47	$1.64	$1.46	$1.95	$1.92	$1.42	$1.48	$1.54	$1.77	$1.77	$1.83	$1.71	$1.64
	-$5 to -$10	$7.32	$6.91	$6.99	$7.04	$6.93	$6.86	$6.91	$6.82	$6.71	$6.99	$7.10	$7.04	$6.98
	-$10 to -$20	$14.65	$13.98	$14.07	$14.30	$14.00	$14.12	$14.16	$14.01	$14.34	$13.82	$13.99	$14.38	$14.19
	< -$20	$96.24	$54.71	$48.96	$59.75	$81.75	$55.52	$62.12	$68.31	$64.75	$52.57	$49.34	$81.32	$72.89
Interval	Range of Price Differences	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	YTD Avg
~ 90 Minutes Prior to Real-Time	> $20	$59.14	$29.66	$26.44	$39.98	$54.50	$36.65	$49.29	$40.08	$54.49	$27.94	$31.28	$43.17	$45.83
	$10 to $20	$14.43	$13.29	$14.00	$13.79	$13.33	$13.77	$13.53	$13.94	$13.99	$13.79	$13.70	$15.08	$13.79
	$5 to $10	$7.10	$6.77	$7.05	$7.10	$7.31	$6.84	$7.09	$7.04	$7.07	$7.07	$7.26	$6.77	$7.10
	$0 to $5	$1.41	$1.49	$1.65	$2.07	$2.15	$1.39	$1.59	$1.86	$1.93	$1.86	$1.63	$1.61	$1.72
	$0 to -$5	$1.61	$1.73	$1.65	$1.96	$1.92	$1.59	$1.48	$1.61	$1.77	$1.99	$2.00	$2.07	$1.78
	-$5 to -$10	$7.16	$6.76	$7.27	$7.01	$7.15	$6.90	$6.88	$6.88	$6.82	$6.78	$6.90	$7.06	$6.97
	-$10 to -$20	$14.47	$13.91	$14.20	$14.01	$13.49	$14.25	$14.15	$14.52	$14.22	$13.86	$14.18	$14.67	$14.19
	< -$20	$97.09	$56.68	$47.54	$60.43	$82.84	$56.08	$61.34	$69.44	$66.88	$52.08	$52.03	$77.49	$73.98
Interval	Range of Price Differences	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	YTD Avg
~ 135 Minutes Prior to Real-Time	> $20	$65.20	$33.05	$25.35	$42.94	$43.44	$35.38	$47.66	$36.10	$58.34	$29.10	$33.11	$47.17	$48.56
	$10 to $20	$14.92	$13.48	$13.89	$13.93	$13.73	$13.58	$13.48	$14.37	$14.26	$14.24	$13.89	$14.34	$14.01
	$5 to $10	$7.02	$6.84	$7.16	$7.31	$7.45	$7.10	$7.36	$7.34	$7.15	$7.09	$7.12	$6.85	$7.22
	$0 to $5	$1.47	$1.48	$1.73	$2.17	$2.22	$1.50	$1.70	$1.91	$2.01	$1.87	$1.65	$1.56	$1.78
	$0 to -$5	$1.78	$1.91	$1.72	$2.11	$2.12	$1.77	$1.71	$1.93	$1.96	$1.98	$2.01	$2.10	$1.92
	-$5 to -$10	$7.14	$6.78	$7.22	$7.21	$6.98	$7.01	$6.77	$6.82	$6.87	$6.73	$6.97	$6.95	$6.95
	-$10 to -$20	$14.61	$13.76	$14.21	$13.71	$13.87	$13.84	$14.42	$14.67	$14.48	$13.84	$14.34	$14.54	$14.23
	< -$20	$98.34	$54.78	$46.99	$61.37	$135.81	$55.11	$206.85	$69.10	$81.01	$51.51	$49.37	$79.58	$90.03

The NYISO uses PJM's ITSCED forecasted LMPs to compare against the NYISO Real-Time Commitment (RTC) results in its evaluation of CTS transactions. The NYISO approves CTS (spread bid) transactions when the offered spread is less than or equal to the spread between the ITSCED forecast PJM/NYIS interface LMP and the NYISO RTC forecast NYIS/PJM interface LMP. The large differences between forecast and actual LMPs in the intervals closest to real-time could cause CTS transactions to be approved that would contribute to transactions being scheduled counter to real-time economic signals, and contribute to inefficient scheduling across the PJM/NYIS border.

CTS transactions are evaluated based on the spread bid, which limits the amount of price convergence that can occur. As long as balancing operating reserve charges are applied and CTS transactions are optional, the CTS proposal represents a small incremental step toward better interface pricing. The NYISO has a 75 minute bid submission deadline. While market participants have the option to specify bid data on 15 minute intervals, market participants must submit their bids 75 minutes prior to the requested transaction start time. The 75 minute bid submission deadline associated with scheduling energy transactions in the NYISO should be shortened. Reducing this deadline could significantly improve pricing efficiency at the PJM/NYISO border for non-CTS transactions and for CTS transactions as market participants would be able to adjust their bids in response to real-time price signals.

CTS transactions were evaluated for each 15 minute interval. From November 4, 2014, through December 31, 2018, 196,904 15 minute CTS schedules were approved through the CTS process based on the forecast LMPs. When the forecast LMPs for the approved intervals were compared to the hourly integrated real-time LMPs, the direction of the flow in 63,428 (32.2 percent) of the intervals was inconsistent with the differences in real-time PJM/NYISO and NYISO/PJM prices. For example, if a market participant submits a CTS transaction from NYISO to PJM with a spread bid of $5.00, and NYISO's forecasted PJM interface price was at least $5.00 lower than PJM's forecasted NYISO interface price, the transaction would be approved. For 32.2 percent of the approved transactions, the actual, real-time price differentials were in the opposite direction of the forecast differential. The actual, real-time price differentials meant that the transactions would have been economic in the opposite direction. For 67.8 percent of the intervals, the forecast price differentials were consistent with real-time PJM/NYISO and NYISO/PJM price differences. Figure 9-14 shows the monthly volume of cleared PJM/NYIS CTS bids. Figure 9-14 also shows the percent of cleared bids that resulted in flows consistent and inconsistent with price differences.

Figure 9-14 Monthly cleared PJM/NYIS CTS bid volume: November 4, 2014 through 2018



The data reviewed show that ITSCED is not a highly accurate predictor of the real-time PJM/NYIS interface prices. If this remains true, it will limit the effectiveness of CTS in improving interface pricing between PJM and NYISO.

Reserving Ramp on the PJM/NYISO Interface

Prior to the implementation of CTS, PJM held ramp space for all transactions submitted between PJM and the NYISO as soon as the NERC Tag was approved. At that time, once transactions were evaluated by the NYISO through their real-time market clearing process, any adjustments made to the submitted transactions would be reflected on the NERC Tags and the PJM ramp was adjusted accordingly.

As part of this process, PJM was often required to make adjustments to transactions on its other interfaces in order to bring total system ramp back to within its limit. The default ramp limit in PJM is +/- 1,000 MW. For example, the ramp in a given interval is currently -1,000 MW, consisting of 2,000 MW of imports from the NYISO to PJM and 3,000 MW of exports from PJM on its other interfaces. If, through the NYISO real-time market clearing process, the NYISO only approves 1,000 MW of the imports, the other 1,000 MW of import transactions from the NYISO would be curtailed. The ramp in this interval would then be -2,000 MW, consisting of the 1,000 MW of cleared imports from the NYISO to PJM and 3,000 MW of exports from PJM on its other interfaces. PJM would then be required to curtail an additional 1,000 MW of exports at its other interface to bring the limit back to within +/- 1,000. These curtailments were made on a last in first out basis as determined by the timestamp on the NERC Tag.

With the implementation of the CTS product with the NYISO, PJM modified how ramp is handled at the PJM/NYISO Interface. Effective November 4, 2014, PJM no longer holds ramp room for any transactions submitted between PJM and the NYISO at the time of submission. Only after the NYISO completes its real-time market clearing process, and communicates the results to PJM, does PJM perform a ramp evaluation on transactions scheduled with the NYISO. If, in the event the NYISO market clearing process would violate ramp, PJM would make additional adjustments based on a last-in first-out basis as determined by the timestamp on the NERC Tag. This process prevents the transactions scheduled at the PJM/NYISO interface from holding (or creating) ramp until NYISO has completed its economic evaluation and the transactions are approved through the NYISO market clearing process.

PJM and MISO Coordinated Interchange Transaction Proposal

PJM and MISO proposed the implementation of coordinated interchange transactions, similar to the PJM/NYISO approach, through the Joint and Common Market Initiative. The PJM/MISO coordinated transaction scheduling (CTS) process provides the option for market participants to submit intra-hour transactions between the MISO and PJM that include an interface spread bid on which transactions are evaluated. Similar to the PJM/NYISO approach, the evaluation is based, in part, on the forward-looking prices as determined by PJM's intermediate term security constrained economic dispatch tool (ITSCED). Unlike the PJM/NYISO CTS process in which the NYISO performs the evaluation, the PJM/MISO CTS process uses a joint clearing process in which both RTOs share forward looking prices. On October 3, 2017, PJM and MISO implemented the CTS process.

To evaluate the accuracy of ITSCED forecasts, the forecasted PJM/MISO interface price for each 15 minute interval from ITSCED was compared to the actual real-time interface LMP for 2018. Table 9-45 shows that over all 12 forecast ranges, ITSCED predicted the real-time PJM/MISO interface LMP within the range of $0.00 to $5.00 in 24.9 percent of all intervals. In those intervals, the average price difference between the ITSCED forecasted LMP and the actual real-time LMP was $1.75. In 8.9 percent of all intervals, the absolute value of the average price difference between the ITSCED forecasted LMP and the actual real-time interface LMP was greater than $20.00. The average price differences were $54.62 when the price difference was greater than $20.00, and $64.92 when the price difference was greater than -$20.00.

Table 9-45 Differences between forecast and actual PJM/MISO interface prices: 2018

Range of Price Differences	Percent of All Intervals	Average Price Difference
> $20	3.8%	$54.62
$10 to $20	5.9%	$13.98
$5 to $10	7.9%	$7.19
$0 to $5	24.9%	$1.75
$0 to -$5	39.9%	$1.76
-$5 to -$10	7.6%	$7.03
-$10 to -$20	4.9%	$14.22
< -$20	5.1%	$64.92

Table 9-46 shows how the accuracy of the ITSCED forecasted LMPs change as the cases approach real-time. In the final ITSCED results prior to real-time, in 65.4 percent of all intervals, the average price difference between the ITSCED forecasted LMP and the actual real-time interface LMP fell within +/- $5.00 of the actual PJM/MISO interface real-time LMP, compared to 62.1 percent in the 135 minute ahead ITSCED results.

Table 9-46 Differences between forecast and actual PJM/MISO interface prices: 2018

	~ 135 Minutes Prior to Real-Time		~ 90 Minutes Prior to Real-Time		~ 45 Minutes Prior to Real-Time		~ 30 Minutes Prior to Real-Time	
Range of Price Differences	Percent of Intervals	Average Price Difference	Percent of Intervals	Average Price Difference	Percent of Intervals	Average Price Difference	Percent of Intervals	Average Price Difference
> $20	3.4%	$38.98	3.0%	$38.31	3.2%	$45.87	4.4%	$60.93
$10 to $20	6.1%	$14.18	5.2%	$13.91	5.7%	$13.85	6.1%	$14.03
$5 to $10	7.4%	$7.20	8.0%	$7.12	8.1%	$7.15	8.0%	$7.18
$0 to $5	21.2%	$1.82	26.3%	$1.78	27.8%	$1.74	25.5%	$1.74
$0 to -$5	40.8%	$1.93	38.9%	$1.79	38.9%	$1.66	39.9%	$1.66
-$5 to -$10	8.9%	$7.01	7.6%	$7.01	6.6%	$7.06	6.7%	$7.03
-$10 to -$20	6.1%	$14.27	5.3%	$14.22	4.3%	$14.25	4.2%	$14.18
< -$20	6.1%	$77.18	5.7%	$60.58	5.3%	$61.31	5.2%	$63.62

In 9.7 percent of the intervals in the 30 minute ahead forecast, the absolute value of the average price difference between the ITSCED forecasted LMP and the actual real-time interface LMP was greater than $20.00, the average price differences were $60.93 when the price difference was greater than $20.00, and $63.62 when the price difference was greater than -$20.00.

Table 9-47 and Table 9-48 show the monthly differences between forecasted and actual PJM/MISO interface prices. Analysis of the data on a monthly basis shows that there is a decline in the accuracy of the ITSCED forecast ability during periods of cold and hot weather.

Table 9-47 Monthly Differences between forecast and actual PJM/MISO interface prices (percent of intervals): 2018

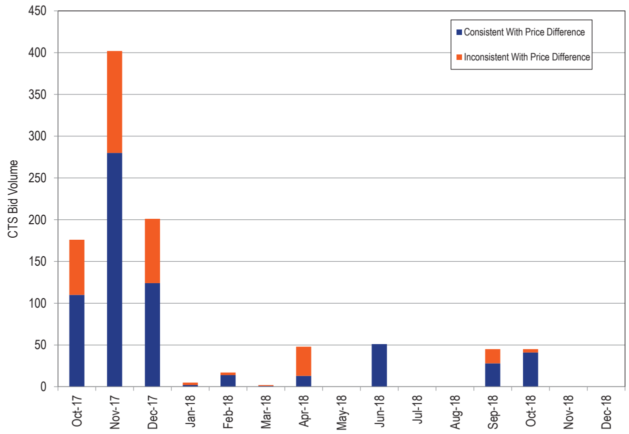
Interval	Range of Price Differences	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	YTD Avg
~ 30 Minutes Prior to Real-Time	> $20	7.8%	0.6%	4.1%	7.5%	9.7%	2.4%	3.1%	3.8%	7.3%	3.4%	2.8%	0.8%	4.4%
	$10 to $20	4.8%	0.7%	3.5%	10.1%	13.1%	3.9%	7.1%	5.6%	6.5%	9.2%	6.8%	1.7%	6.1%
	$5 to $10	5.2%	2.1%	6.1%	13.3%	15.8%	6.2%	7.8%	8.0%	8.4%	11.8%	7.4%	3.8%	8.0%
	$0 to $5	16.0%	27.4%	30.2%	24.9%	26.4%	31.8%	22.9%	20.8%	19.2%	33.1%	29.1%	24.1%	25.5%
	$0 to -$5	36.8%	59.1%	38.0%	24.9%	19.4%	43.7%	46.5%	48.4%	43.3%	28.2%	35.8%	55.0%	39.9%
	-$5 to -$10	7.4%	6.1%	6.9%	6.6%	4.7%	5.5%	5.6%	6.5%	7.9%	6.8%	6.9%	8.8%	6.7%
	-$10 to -$20	7.2%	1.8%	4.8%	6.0%	4.0%	3.2%	3.3%	3.4%	3.5%	3.5%	5.7%	3.9%	4.2%
	< -$20	14.8%	2.1%	6.4%	6.8%	7.0%	3.2%	3.7%	3.5%	4.0%	3.9%	5.5%	1.8%	5.2%
Interval	Range of Price Differences	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	YTD Avg
~ 45 Minutes Prior to Real-Time	> $20	7.1%	0.3%	3.3%	3.8%	5.2%	2.0%	1.9%	2.6%	5.0%	3.6%	2.5%	0.4%	3.2%
	$10 to $20	5.5%	0.3%	3.7%	8.9%	12.1%	3.6%	6.1%	4.6%	6.1%	8.9%	6.7%	1.7%	5.7%
	$5 to $10	4.3%	2.0%	6.4%	14.0%	15.1%	6.4%	7.6%	8.6%	9.2%	12.3%	7.2%	3.6%	8.1%
	$0 to $5	18.7%	31.4%	33.6%	27.9%	29.8%	36.3%	26.2%	23.6%	22.1%	31.9%	28.5%	24.4%	27.8%
	$0 to -$5	34.9%	56.8%	35.8%	25.4%	19.9%	39.5%	46.0%	47.9%	42.7%	28.9%	35.8%	54.4%	38.9%
	-$5 to -$10	7.0%	5.3%	7.0%	7.3%	6.1%	5.8%	4.6%	5.5%	6.9%	6.5%	7.9%	9.6%	6.6%
	-$10 to -$20	7.1%	1.9%	4.5%	5.6%	4.5%	3.2%	3.8%	3.3%	3.7%	3.9%	6.0%	4.1%	4.3%
	< -$20	15.3%	2.0%	5.7%	7.0%	7.2%	3.2%	3.9%	3.9%	4.4%	4.0%	5.4%	1.9%	5.3%
Interval	Range of Price Differences	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	YTD Avg
~ 90 Minutes Prior to Real-Time	> $20	6.6%	0.2%	3.7%	4.0%	5.3%	1.6%	2.1%	2.9%	4.1%	2.5%	2.7%	0.4%	3.0%
	$10 to $20	4.6%	0.7%	4.4%	9.5%	12.7%	4.0%	5.5%	5.5%	5.5%	4.3%	4.3%	1.3%	5.2%
	$5 to $10	4.9%	3.0%	6.6%	13.4%	15.4%	6.6%	9.4%	9.0%	10.2%	7.0%	6.7%	3.1%	8.0%
	$0 to $5	20.5%	33.8%	34.9%	27.0%	28.5%	38.4%	27.5%	24.8%	22.1%	21.7%	20.2%	17.7%	26.3%
	$0 to -$5	33.0%	53.6%	32.7%	24.8%	19.8%	37.5%	43.5%	45.4%	40.7%	38.6%	40.7%	57.0%	38.9%
	-$5 to -$10	7.2%	4.7%	7.4%	8.1%	6.1%	5.9%	4.7%	5.0%	8.1%	11.2%	10.3%	12.4%	7.6%
	-$10 to -$20	7.7%	2.0%	4.5%	5.8%	4.6%	2.8%	3.4%	3.4%	4.6%	9.5%	8.6%	5.9%	5.3%
	< -$20	15.5%	2.1%	5.8%	7.3%	7.6%	3.1%	3.9%	4.0%	4.8%	5.2%	6.4%	2.2%	5.7%
Interval	Range of Price Differences	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	YTD Avg
~ 135 Minutes Prior to Real-Time	> $20	11.5%	0.5%	4.4%	6.6%	3.7%	1.3%	2.0%	2.2%	3.9%	1.8%	2.5%	0.5%	3.4%
	$10 to $20	6.7%	1.1%	6.1%	11.3%	11.6%	3.9%	5.8%	8.1%	6.5%	4.7%	5.5%	1.1%	6.1%
	$5 to $10	5.6%	3.0%	9.2%	12.2%	12.7%	5.1%	8.6%	7.1%	9.1%	6.7%	6.2%	2.6%	7.4%
	$0 to $5	16.7%	27.0%	29.6%	24.2%	19.6%	23.4%	20.7%	17.6%	18.6%	20.9%	19.9%	17.1%	21.2%
	$0 to -$5	32.7%	58.0%	29.6%	24.0%	24.5%	48.5%	48.4%	47.8%	41.7%	39.2%	39.8%	57.3%	40.8%
	-$5 to -$10	7.5%	6.2%	9.2%	8.4%	9.3%	8.2%	5.4%	8.0%	9.4%	11.4%	10.7%	13.3%	8.9%
	-$10 to -$20	6.4%	2.4%	5.6%	6.4%	7.5%	5.1%	4.6%	4.8%	5.3%	9.5%	9.4%	5.8%	6.1%
	< -$20	12.9%	1.9%	6.4%	7.0%	11.2%	4.4%	4.5%	4.5%	5.6%	5.6%	6.1%	2.3%	6.1%

Table 9-48 Monthly differences between forecast and actual PJM/MISO interface prices (average price difference): 2018

Interval	Range of Price Differences	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	YTD Avg
~ 30 Minutes Prior to Real-Time	> $20	$51.76	$38.72	$65.38	$81.77	$50.97	$43.57	$93.11	$81.08	$71.05	$33.06	$29.85	$44.30	$60.93
	$10 to $20	$14.48	$13.95	$14.04	$13.94	$14.04	$14.21	$13.84	$13.86	$13.82	$13.91	$14.50	$13.73	$14.03
	$5 to $10	$7.34	$6.66	$6.92	$7.34	$7.17	$7.28	$7.19	$7.06	$7.16	$7.23	$7.29	$6.93	$7.18
	$0 to $5	$1.52	$1.49	$1.78	$2.19	$2.09	$1.31	$1.68	$2.05	$1.98	$1.77	$1.76	$1.32	$1.74
	$0 to -$5	$1.43	$1.59	$1.73	$1.98	$1.86	$1.36	$1.52	$1.52	$2.02	$1.76	$1.78	$1.69	$1.66
	-$5 to -$10	$7.41	$6.90	$7.07	$7.08	$6.91	$6.76	$6.87	$6.85	$6.91	$7.19	$7.21	$7.00	$7.03
	-$10 to -$20	$14.12	$13.53	$14.23	$14.38	$13.46	$14.44	$14.34	$14.48	$14.75	$14.60	$13.95	$13.85	$14.18
	< -$20	$71.82	$48.27	$59.63	$53.61	$102.79	$51.68	$50.05	$53.28	$62.58	$56.99	$42.54	$66.01	$63.62
Interval	Range of Price Differences	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	YTD Avg
~ 45 Minutes Prior to Real-Time	> $20	$46.02	$49.64	$60.26	$33.30	$34.81	$40.92	$118.49	$39.69	$49.89	$34.20	$33.25	$29.45	$45.87
	$10 to $20	$14.11	$12.38	$13.99	$13.86	$13.66	$13.50	$13.74	$13.82	$13.97	$13.61	$14.66	$13.27	$13.85
	$5 to $10	$7.25	$6.61	$6.90	$7.21	$7.27	$6.94	$7.06	$7.11	$7.18	$7.23	$7.20	$7.22	$7.15
	$0 to $5	$1.42	$1.47	$1.80	$2.18	$2.22	$1.24	$1.77	$1.89	$1.99	$1.81	$1.79	$1.36	$1.74
	$0 to -$5	$1.45	$1.52	$1.72	$1.95	$2.01	$1.44	$1.44	$1.48	$1.89	$1.81	$1.84	$1.73	$1.66
	-$5 to -$10	$7.40	$6.88	$7.08	$7.01	$7.17	$7.02	$6.99	$6.75	$6.89	$7.19	$7.16	$7.03	$7.06
	-$10 to -$20	$14.39	$14.15	$14.07	$14.24	$14.12	$14.28	$14.00	$14.61	$14.28	$14.28	$14.34	$14.17	$14.25
	< -$20	$73.06	$49.94	$62.42	$55.51	$72.45	$53.13	$49.86	$50.57	$62.25	$57.32	$44.39	$63.94	$61.31
Interval	Range of Price Differences	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	YTD Avg
~ 90 Minutes Prior to Real-Time	> $20	$42.64	$53.86	$56.85	$32.40	$32.53	$36.77	$43.00	$35.97	$40.62	$27.42	$28.65	$31.98	$38.31
	$10 to $20	$14.56	$12.68	$13.75	$13.95	$13.95	$13.38	$13.59	$14.00	$13.70	$13.85	$14.41	$14.01	$13.91
	$5 to $10	$7.47	$6.70	$6.94	$7.01	$7.24	$7.02	$7.08	$7.21	$7.24	$7.00	$7.14	$6.96	$7.12
	$0 to $5	$1.44	$1.53	$1.88	$2.16	$2.24	$1.42	$1.70	$1.85	$2.03	$1.82	$1.78	$1.48	$1.78
	$0 to -$5	$1.56	$1.54	$1.82	$2.07	$2.03	$1.53	$1.45	$1.53	$1.96	$2.12	$1.96	$2.11	$1.79
	-$5 to -$10	$7.28	$6.72	$7.08	$6.99	$7.11	$6.99	$7.22	$6.71	$6.80	$7.07	$7.08	$6.97	$7.01
	-$10 to -$20	$14.50	$13.73	$13.99	$14.44	$14.09	$14.12	$14.27	$13.85	$14.17	$14.19	$14.26	$14.31	$14.22
	< -$20	$75.72	$48.12	$58.98	$53.28	$69.97	$53.32	$48.57	$49.43	$63.96	$58.45	$41.17	$63.72	$60.58
Interval	Range of Price Differences	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	YTD Avg
~ 135 Minutes Prior to Real-Time	> $20	$44.43	$38.44	$54.01	$34.21	$32.32	$39.98	$31.54	$27.23	$42.49	$27.55	$29.13	$32.83	$38.98
	$10 to $20	$14.70	$13.01	$13.96	$14.27	$14.29	$13.82	$14.01	$13.95	$14.15	$14.47	$14.35	$13.55	$14.18
	$5 to $10	$7.50	$6.80	$7.07	$7.20	$7.26	$7.19	$7.27	$7.48	$7.00	$7.09	$7.13	$7.15	$7.20
	$0 to $5	$1.53	$1.58	$1.95	$2.20	$2.25	$1.37	$1.82	$1.82	$2.13	$1.86	$1.74	$1.53	$1.82
	$0 to -$5	$1.67	$1.69	$1.92	$2.15	$2.20	$1.80	$1.70	$1.87	$2.14	$2.14	$1.96	$2.09	$1.93
	-$5 to -$10	$7.23	$6.74	$7.07	$7.15	$7.07	$7.02	$6.86	$6.68	$6.76	$7.10	$7.13	$7.07	$7.01
	-$10 to -$20	$14.21	$14.34	$13.89	$14.40	$14.16	$14.34	$14.46	$14.58	$14.61	$13.94	$14.27	$14.49	$14.27
	< -$20	$77.99	$50.78	$55.95	$55.10	$100.97	$46.91	$240.54	$47.35	$63.87	$57.95	$42.86	$60.31	$77.18

CTS transactions were evaluated for each interval. From October 3, 2017, through December 31, 2018, 992 CTS schedules were approved through the CTS process based on the forecast LMPs. When the forecast LMPs for the approved intervals were compared to the hourly integrated real-time LMPs, the direction of the flow in 328 (33.1 percent) of the intervals was inconsistent with the differences in real-time PJM/MISO and MISO/PJM prices. For example, if a market participant submits a CTS transaction from MISO to PJM with a spread bid of $5.00, and MISO's forecasted PJM interface price was at least $5.00 lower than PJM's forecasted MISO interface price, the transaction would be approved. For 33.1 percent of the approved transactions, the actual, real-time price differentials were in the opposite direction of the forecast differential. The actual, real-time price differentials meant that the transactions would have been economic in the opposite direction. For 66.9 percent of the intervals, the forecast price differentials were consistent with real-time PJM/MISO and MISO/PJM price differences. Figure 9-15 shows the monthly volume of cleared PJM/MISO CTS bids. Figure 9-15 also shows the percent of cleared bids that resulted in flows consistent and inconsistent with price differences.

Figure 9-15 Monthly cleared PJM/MISO CTS bid volume: October 3, 2017 through 2018



The data reviewed show that ITSCED is not a highly accurate predictor of the real-time PJM/MISO interface prices. If this remains true, it will limit the effectiveness of CTS in improving interface pricing between PJM and MISO.

Willing to Pay Congestion and Not Willing to Pay Congestion

When reserving nonfirm transmission, market participants have the option to choose whether or not they are willing to pay congestion. When the market participant elects to pay congestion, PJM operators redispatch the system if necessary to allow the energy transaction to continue to flow. The system redispatch often creates price separation across buses on the PJM system. The difference in LMPs between two buses in PJM is the congestion cost (and losses) that the market participant pays in order for their transaction to continue to flow.

The MMU recommended that PJM modify the not willing to pay congestion product to address the issues of uncollected congestion charges. The MMU recommended charging market participants for any congestion incurred while the transaction is loaded, regardless of their election of transmission service, and restricting the use of not willing to pay congestion transactions (as well as all other real-time external energy transactions) to transactions at interfaces.

On April 12, 2011, the PJM Market Implementation Committee (MIC) endorsed the changes recommended by the MMU. The elimination of internal sources and sinks on transmission reservations addressed most of the MMU concerns, as there can no longer be uncollected congestion charges for imports to PJM or exports from PJM. There is still potential exposure to uncollected congestion charges in wheel through transactions, and the MMU will continue to evaluate if additional mitigation measures would be appropriate to address this exposure.

Table 9-49 shows that since the inception of the business rule change on April 12, 2013, there was uncollected congestion in only one month, January 2016. The negative congestion means that market participants who used the not willing to pay congestion transmission option for their wheel through transactions had transactions that flowed in the direction opposite to congestion. When market participants use the not willing to pay congestion product, it also means that they are not willing to receive congestion credits, which was the case in January 2016.

Table 9-49 Monthly uncollected congestion charges: 2010 through 2018

Month	2010	2011	2012	2013	2014	2015	2016	2017	2018
Jan	$148,764	$3,102	$0	$5	$0	$0	($44)	$0	$0
Feb	$542,575	$1,567	($15)	$249	$0	$0	$0	$0	$0
Mar	$287,417	$0	$0	$0	$0	$0	$0	$0	$0
Apr	$31,255	$4,767	($68)	($3,114)	$0	$0	$0	$0	$0
May	$41,025	$0	($27)	$0	$0	$0	$0	$0	$0
Jun	$169,197	$1,354	$78	$0	$0	$0	$0	$0	$0
Jul	$827,617	$1,115	$0	$0	$0	$0	$0	$0	$0
Aug	$731,539	$37	$0	$0	$0	$0	$0	$0	$0
Sep	$119,162	$0	$0	$0	$0	$0	$0	$0	$0
Oct	$257,448	($31,443)	($6,870)	$0	$0	$0	$0	$0	$0
Nov	$30,843	($795)	($4,678)	$0	$0	$0	$0	$0	$0
Dec	$127,176	($659)	($209)	$0	$0	$0	$0	$0	$0
Total	$3,314,018	($20,955)	($11,789)	($2,860)	$0	$0	($44)	$0	$0

Spot Imports

Prior to April 1, 2007, PJM did not limit nonfirm service imports that were willing to pay congestion, including spot imports, secondary network service imports and bilateral imports using nonfirm point-to-point service. Spot market imports, nonfirm point-to-point and network services that are willing to pay congestion, all termed willing to pay congestion (WPC), were part of the PJM LMP energy market design implemented on April 1, 1998. Under this approach, market participants could offer energy into or bid to buy from the PJM spot market at the border/interface as price takers without restrictions based on estimated available transmission capability (ATC). Price and PJM system conditions, rather than ATC, were the only limits on interchange.

However, PJM has interpreted its JOA with MISO to require restrictions on spot imports and exports although MISO has not implemented a corresponding restriction.[102] The result is that the availability of spot import service is limited by ATC and not all spot transactions are approved. Spot import service (a network service) is provided at no charge to the market participant offering into the PJM spot market.

The spot import rules provide incentives to hoard spot import capability. In response to market participant complaints regarding the inability to acquire spot import service after this rule change on April 1, 2007, changes were made to the spot import service effective May 1, 2008.[103] These changes limited spot imports to only hourly reservations and caused spot import service to expire if not associated with a valid NERC Tag within two hours when reserved the day prior to the scheduled flow or within 30 minutes when reserved on the day of the scheduled flow.

These changes did not fully resolve the issue. In the *2008 State of the Market Report for PJM*, the MMU recommended that PJM reconsider whether a new approach to limiting spot import service is required or whether a return to the prior policy with an explicit system of managing related congestion is preferable. PJM and the MMU jointly addressed this issue through the stakeholder process, recommending that all unused spot import service be retracted if not tagged within 30 minutes from the queue time of the reservations intraday, and two hours when queued the day prior. On June 23, 2009, PJM implemented the new business rules.

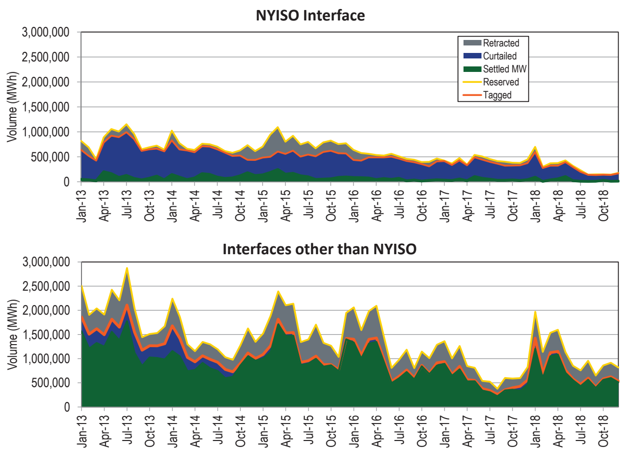
Figure 9-16 shows the spot import service use for the NYISO Interface, and for all other interfaces, from January 1, 2013 through December 31, 2018. The yellow line shows the total monthly MWh of spot import service reserved and the orange line shows the total monthly MWh of tagged spot import service. The gray shaded area between the yellow and orange lines represents the MWh of retracted spot import service and may represent potential hoarding volumes. This ATC was initially reserved, but not tagged (used). It is possible that in some instances the reserved transmission consisted of the only available ATC which could have been used by another market participant had it not been reserved and not used. The blue shaded area between the orange line and green shaded area represents the MWh of curtailed transactions using spot import service. This area may also represent hoarding opportunities, particularly at the NYISO Interface. In this instance, it is possible that while the market participant reserved and scheduled the transmission, they may have submitted purposely uneconomic bids in the NYISO market so that their transaction would be curtailed, yet their transmission would not be retracted. The NYISO allows for market participants to modify their bids on an hourly basis, so these market participants can hold their transmission service and evaluate their bids hourly, while withholding

102 See OASIS "Modifications to the Practices of Non-Firm and Spot Market Import Service" (April 20, 2007) <http://www.pjm.com/~/media/etools/oasis/wpc-white-paper.ashx>.

103 See OASIS "Regional Transmission and Energy Scheduling Practices," Rev. 7 (December 19, 2018) <http://www.pjm.com/~/media/etools/oasis/regional-practices-clean-pdf.ashx>.

the transmission from other market participants that may wish to use it. The green shaded area represents the total settled MWh of spot import service. Figure 9-16 shows that while there are proportionally fewer retracted MWh on the NYISO Interface than on all other interfaces, the NYISO has proportionally more curtailed MWh. This is a result of the NYISO market clearing process.

Figure 9-16 Spot import service use: 2013 through 2018



The MMU continues to recommend that PJM permit unlimited spot market imports (as well as all nonfirm point-to-point willing to pay congestion imports and exports) at all PJM interfaces.

Interchange Optimization

When PJM prices are higher than prices in surrounding balancing authorities, imports will flow into PJM until the prices are approximately equal. This is an appropriate market response to price differentials. Given the nature of interface pricing and the treatment of interface transactions, it is not possible for PJM system operators to reliably predict the quantity or sustainability of such imports. The inability to predict interchange volumes creates additional challenges for PJM dispatch in trying to meet loads, especially on high-load days. If all external transactions were submitted as real-time dispatchable transactions during emergency conditions, PJM would be able to include interchange transactions in its supply stack, and dispatch only enough interchange to meet the demand.

The MMU recommends that the submission deadline for real-time dispatchable transactions be modified from 1800 on the prior day to three hours prior to the requested start time, and that the minimum duration be modified from one hour to 15 minutes.[104] These changes would give PJM a more flexible product that could be used to meet load based on economic dispatch rather than guessing the sensitivity of the transactions to price changes.

In addition to changing prices, transmission line loading relief procedures (TLRs), market participants' curtailments for economic reasons, and external balancing authority curtailments affect the duration of interchange transactions.

The MMU recommends that PJM explore an interchange optimization solution with its neighboring balancing authorities that would remove the need for market participants to schedule physical transactions across seams. Such a solution would include an optimized, but limited, joint dispatch approach that uses supply curves and treats seams between balancing authorities as constraints, similar to other constraints within an LMP market.

Interchange Cap During Emergency Conditions

An interchange cap is a limit on the level of interchange permitted for nondispatchable energy using spot import or hourly point-to-point transmission. An interchange cap is a nonmarket intervention which should be a temporary solution and should be replaced with a market-based solution as soon as possible. Since the approval of this process on October 30, 2014, PJM has not yet needed to implement an interchange cap.

The purpose of the interchange cap is to help ensure that actual interchange more closely meets operators' expectations of interchange levels when internal PJM resources, e.g. CTs or demand response, were dispatched to meet the peak load. Once these resources have been called on, PJM must honor their minimum operating constraints regardless of whether additional interchange then materializes. Therefore any interchange received in excess of what was expected can have a suppressive effect on energy and reserve pricing and result in increased uplift.

104 The minimum duration for a real-time dispatchable transaction was modified to 15 minutes as per FERC Order No. 764.

PJM will notify market participants of the possible use of the interchange cap the day before. The interchange cap will be implemented for the forecasted peak and surrounding hours during emergency conditions.

The interchange cap will limit the acceptance of spot import and hourly nonfirm point to point interchange (imports and exports) not submitted as real-time with price transactions once net interchange has reached the interchange cap value. Spot imports and hourly nonfirm point to point transactions submitted prior to the implementation of the interchange cap will not be limited. In addition, schedules with firm or network designated transmission service will not be limited either, regardless of whether net interchange is at or above the cap.

The calculation of the interchange cap is based on the operator expectation of interchange at the time the cap is calculated plus an additional margin. The margin is set at 700 MW, which is half of the largest contingency on the system. The additional margin also allows interchange to adjust to the loss of a unit or deviation between actual load and forecasted load. The interchange cap is based on the maximum sustainable interchange from PJM reliability studies.

45 Minute Schedule Duration Rule

PJM limits the change in interchange volumes on 15 minute intervals. These changes are referred to as ramp. The purpose of imposing a ramp limit is to help ensure the reliable operation of the PJM system. The 1,000 MW ramp limit per 15 minute interval was based on the availability of ramping capability by generators in the PJM system. The limit is consistent with the view that the available generation in the PJM system can only move 1,000 MW over any 15 minute period although that has not been shown to be correct. The PJM ramp limit is designed to limit the change in the amount of imports or exports in each 15 minute interval to account for the physical characteristics of the generation to respond to changes in the level of imports and exports. For example, if at 0800 the sum of all external transactions were -3,000 MW (negative sign indicates net exporting), the limit for 0815 would be -2,000 MW to -4,000 MW. In other words, the starting or ending of transactions would be limited so that the overall change from the previous 15 minute period would not exceed 1,000 MW in either direction.

In 2008, there was an increase in 15 minute external energy transactions that caused swings in imports and exports submitted in response to intra-hour LMP changes. This activity was due to market participants' ability to observe price differences between RTOs in the first third of the hour, and predict the direction of the price difference on an hourly integrated basis. Large quantities of MW would then be scheduled between the RTOs for the last 15 minute interval to capture those hourly integrated price differences with relatively little risk of prices changing. This increase in interchange on 15 minute intervals created operational control issues, and in some cases led to an increase in uplift charges due to calling on resources with minimum run times greater than 15 minutes needed to support the interchange transactions. As a result, a new business rule was proposed and approved that required all transactions to be at least 45 minutes in duration.

On June 22, 2012, FERC issued Order No. 764, which required transmission providers to give transmission customers the option to schedule transmission service at 15 minute intervals to reflect more accurate power production forecasts, load and system conditions.[105] [106] On April 17, 2014, FERC issued its order which found that PJM's 45 minute duration rule was inconsistent with Order No. 764.[107]

PJM and the MMU issued a statement indicating ongoing concern about market participants' scheduling behavior, and a commitment to address any scheduling behavior that raises operational or market manipulation concerns.[108]

MISO Multi-Value Project Usage Rate (MUR)

A multi-value project (MVP) is a project, as defined by MISO, which enables the reliable and economic delivery of energy in support of public policy needs, provides multiple types of regional economic value or provides a combination of regional reliability and economic value.[109] On July 15, 2010, MISO submitted revisions to

105 Order No. 764, 139 FERC ¶ 61,246 (2012), *order on reh'g*, Order No. 764-A, 141 FERC ¶ 61231 (2012).

106 Order No. 764 at P 51.

107 *See Id.* at P 12.

108 *See* joint statement of PJM and the MMU re Interchange Scheduling issued July 29, 2014 <http://www.monitoringanalytics.com/reports/Market_Messages/Messages/PJM_IMM_Statement_on_Interchange_Scheduling_20140729.pdf>.

109 See MISO. MTEP "Multi Value Project Portfolio Analysis," <https://cdn.misoenergy.org/2011%20MVP%20Portfolio%20Analysis%20Full%20Report117059.pdf>.

the MISO Tariff to implement criteria for identifying and allocating the costs of MVPs.[110] On December 16, 2010, the Commission accepted the proposed MVP charge for export and wheel-through transactions, except for transactions that sink in PJM.[111] The Commission stated that MISO had not shown that their proposal did not constitute a resumption of rate pancaking along the MISO-PJM seam. Following the December 16, 2010, Order, MISO began applying a multi-value usage rate (MUR) to monthly net actual energy withdrawals, export schedules and through schedules with the exception of transactions sinking in PJM. The MUR charge was applied to the relevant transactions in addition to the applicable transmission, ancillary service and network upgrade charges.

On June 7, 2014, the U.S. Court of Appeals for the Seventh Circuit granted a petition for review regarding the Commission's determination in the MVP Order and MVP Rehearing Order.[112] The Court ordered the Commission to consider on remand whether, in light of current conditions, what if any limitations on export pricing to PJM by MISO are justified.[113] The Seventh Circuit highlighted the fact that at the time of the Commission's decision to prohibit rate pancaking on transactions between MISO and PJM, all of MISO's transmission projects were local and provided only local benefits.[114]

On July 13, 2016, FERC issued an order permitting MISO to collect charges associated with MVPs for all transactions sinking in PJM, effective immediately.[115] The July 13th Order noted that in light of "the development of large scale wind generation capable of serving both MISO's and its neighbors' energy policy requirements in the western areas of MISO; the reported need of PJM entities to access those resources; and the reported need for MISO to build new transmission facilities to deliver the output of those resources within MISO for export… it is appropriate to allow MISO to assess the MVP usage charge for transmission service used to export to PJM just as MISO assesses the MVP usage charge for transmission service used to export energy to other regions."[116]

Table 9-50 shows the projected usage rate to be collected for all wheels through and exports from MISO, including those that sink in PJM, for 2018 through 2037.[117] It is not clear whether the MUR charge has affected interchange volumes from MISO into PJM.

Table 9-50 MISO projected multi value project usage rate: 2018 through 2037

Year	Total Indicative MVP Usage Rate ($/MWh)
2018	$1.70
2019	$1.83
2020	$1.95
2021	$1.94
2022	$1.95
2023	$1.94
2024	$2.03
2025	$1.97
2026	$1.95
2027	$1.93
2028	$1.91
2029	$1.89
2030	$1.87
2031	$1.86
2032	$1.84
2033	$1.82
2034	$1.80
2035	$1.79
2036	$1.77
2037	$1.75

110 See Midwest Independent Transmission Operator Inc. filing, Docket No. ER10-1791-000 (July 15, 2010).
111 133 FERC ¶ 61,221 (2010); *order on reh'g*, 137 FERC ¶ 61,074 (2011).
112 Illinois Commerce Commission, et al. v. FERC, 721 F.3d 764, 778–780 (7th Cir. 2013).
113 *Id.* at 780.
114 *Id.* at 779.
115 156 FERC ¶ 61,034 (2016).
116 *Id.* at P 55.
117 See MISO, "Schedule 26A Indicative Annual Charges" (August 29, 2016) <https://cdn.misoenergy.org/Schedule%2026A%20Indicative%20Annual%20Charges106365.xlsx>.

Ancillary Service Markets

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

The MMU analyzed measures of market structure, conduct and performance for the PJM Synchronized Reserve Market, the PJM DASR Market, and the PJM Regulation Market for 2018.

Table 10-1 The tier 2 synchronized reserve market results were competitive

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

- The tier 2 synchronized reserve market structure was evaluated as not competitive because of high levels of supplier concentration.
- Participant behavior was evaluated as competitive because the market rules require competitive, cost-based offers.
- Market performance was evaluated as competitive because the interaction of participant behavior with the market design results in competitive prices.
- Market design was evaluated as mixed. Market power mitigation rules result in competitive outcomes despite high levels of supplier concentration. However, tier 1 reserves are inappropriately compensated when the nonsynchronized reserve market clears with a nonzero price.

Table 10-2 The day-ahead scheduling reserve market results were competitive

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

- The day-ahead scheduling reserve market structure was evaluated as not competitive because market participants failed the three pivotal supplier test in 9.8 percent of all cleared hours in 2018.
- Participant behavior was evaluated as mixed because while most offers were equal to marginal costs, a significant proportion of offers reflected economic withholding.
- Market performance was evaluated as competitive because there were adequate offers in every hour to satisfy the requirement and the clearing prices reflected those offers, although there is concern about offers above the competitive level affecting prices. Offers above $0.00 were part of the clearing price in 96.4 percent of cleared hours when the clearing price was above $0.
- Market design was evaluated as mixed because the DASR product does not include performance obligations. Offers should be based on opportunity cost only, to ensure competitive outcomes and that market power cannot be exercised.

Table 10-3 The regulation market results were competitive

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

- The regulation market structure was evaluated as not competitive because the PJM Regulation Market failed the three pivotal supplier (TPS) test in 81.7 percent of the hours in 2018.
- Participant behavior in the PJM Regulation Market was evaluated as competitive for 2018 because market power mitigation requires competitive offers when the three pivotal supplier test is failed and there was no evidence of generation owners engaging in noncompetitive behavior.
- Market performance was evaluated as competitive, despite significant issues with the market design.

1 75 FERC ¶ 61,080 (1996).
2 Energy imbalance service refers to the Real-Time Energy Market.

- Market design was evaluated as flawed. The market design has failed to correctly incorporate a consistent implementation of the marginal benefit factor in optimization, pricing and settlement. The market results continue to include the incorrect definition of opportunity cost. The result is significantly flawed market signals to existing and prospective suppliers of regulation.

Overview

Primary Reserve

PJM's primary reserves are made up of resources, both synchronized and nonsynchronized, that can provide energy within 10 minutes. Primary reserve is PJM's implementation of the NERC 15-minute contingency reserve requirement.[3]

On April 1, 2018, PJM implemented five minute settlements. PJM determines the primary reserve requirement based on the most severe single contingency every five minutes. The market solution calculates the available tier 1 synchronized reserve every five minutes. In every five minute interval, the required synchronized reserve and nonsynchronized reserve are calculated and dispatched, and there are associated clearing prices (SRMCP and NSRMCP). Scheduled resources are credited based on their five minute assignment and clearing price.

Market Structure

- **Supply.** Primary reserve is satisfied by both synchronized reserve (generation or demand response currently synchronized to the grid and available within 10 minutes), and nonsynchronized reserve (generation currently off-line but available to start and provide energy within 10 minutes).
- **Demand.** The PJM primary reserve requirement is 150 percent of the most severe single contingency. In 2018, the average primary reserve requirement was 2,267.8 MW in the RTO Zone and 2,247.3 MW in the MAD Subzone.

Tier 1 Synchronized Reserve

Synchronized reserve is provided by generators or demand response resources synchronized to the grid and capable of increasing output or decreasing load within 10 minutes. Synchronized reserve consists of tier 1 and tier 2 synchronized reserves.

Tier 1 synchronized reserve is the capability of online resources following economic dispatch to ramp up in 10 minutes from their current output in response to a synchronized reserve event. There is no formal market for tier 1 synchronized reserve.

- **Supply.** No offers are made for tier 1 synchronized reserves. The market solution estimates tier 1 synchronized reserve as available 10 minute ramp from the energy dispatch. In 2018, there was an average hourly supply of 1,711.9 MW of tier 1 available in the RTO Zone. In 2018, there was an average hourly supply of 771.9 MW of tier 1 synchronized reserve available within the MAD Subzone and an additional 588.2 MW of tier 1 available to the MAD Subzone from the RTO Zone.
- **Demand.** The synchronized reserve requirement is calculated for each five minute interval as the most severe single contingency within both the RTO Zone and the MAD Subzone. The requirement can be met with tier 1 or tier 2 synchronized reserves.
- **Tier 1 Synchronized Reserve Event Response.** Tier 1 synchronized reserve is paid when a synchronized reserve event occurs and it responds. When a synchronized reserve event is called, all tier 1 response is paid the average of five minute LMPs during the event plus $50 per MWh.[4] This is the Synchronized Energy Premium Price.

  Of the Degree of Generator Performance (DGP) adjusted tier 1 synchronized reserve MW estimated at market clearing, 63.3 percent actually responded during the seven synchronized reserve events of 10 minutes or longer in 2018.
- **Issues.** The competitive offer for tier 1 synchronized reserves is zero, as there is no incremental cost associated with the ability to ramp up from the current economic dispatch point and the appropriate payment for responding to an event is

3 See PJM. "Manual 10: Pre-Scheduling Operations," § 3.1.1 Day-ahead Scheduling (Operating Reserve, Rev. 37 (Dec. 10, 2018).

4 See PJM. "Manual 11: Energy & Ancillary Services Market Operations,"§ 4.2.10 Settlements, Rev. 104 (Feb. 7, 2019).

the five-minute LMP plus $50 per MWh. The tariff requires payment of the tier 2 synchronized reserve market clearing price to tier 1 resources whenever the nonsynchronized reserve market clearing price rises above zero. This requirement is unnecessary and inconsistent with efficient markets. This change had a significant impact on the cost of tier 1 synchronized reserves, resulting in a windfall payment of $89,719,045 to tier 1 resources in 2014, $34,397,441 in 2015, $4,948,084 in 2016, $2,197,514 in 2017, and $4,732,025 in 2018.

Tier 2 Synchronized Reserve Market

Tier 2 synchronized reserve is part of primary reserve and is comprised of resources that are synchronized to the grid, that may incur costs to be synchronized, that have an obligation to respond, that have penalties for failure to respond, and that must be dispatched in order to satisfy the synchronized reserve requirement.

When the synchronized reserve requirement cannot be met with tier 1 synchronized reserve, PJM uses a market to satisfy the balance of the requirement with tier 2 synchronized reserve. The Tier 2 Synchronized Reserve Market includes the PJM RTO Reserve Zone and a subzone, the Mid-Atlantic Dominion Reserve Subzone (MAD).

Market Structure

- **Supply.** In 2018, the supply of offered and eligible tier 2 synchronized reserve was 26,086.3 MW in the RTO Zone of which 7,230.9 MW was located in the MAD Subzone. 2,821.0 MW of DSR was available in the RTO Zone.
- **Demand.** The average hourly synchronized reserve requirement was 1,577.8 MW in the RTO Reserve Zone and 1,564.3 MW for the Mid-Atlantic Dominion Reserve Subzone. The hourly average cleared tier 2 synchronized reserve was 352.4 MW in the MAD Subzone and 598.4 MW in the RTO.
- **Market Concentration.** Both the Mid-Atlantic Dominion Subzone Tier 2 Synchronized Reserve Market and the RTO Synchronized Reserve Zone Market were characterized by structural market power in 2018.

  In 2018 10.2 percent of hours would have failed a three pivotal supplier test. In 2018, the average HHI for tier 2 synchronized reserve in the RTO Zone was 5007 which is classified as highly concentrated.

Market Conduct

- **Offers.** There is a must offer requirement for tier 2 synchronized reserve. All nonemergency generation capacity resources are required to submit a daily offer for tier 2 synchronized reserve, unless the unit type is exempt. Tier 2 synchronized reserve offers from generating units are subject to an offer cap of marginal cost plus $7.50 per MW, plus opportunity cost which is calculated by PJM. PJM automatically enters an offer of $0 for tier 2 synchronized reserve when an offer is not entered by the owner.

Market Performance

- **Price.** The weighted average price for tier 2 synchronized reserve for all cleared hours/intervals in the Mid-Atlantic Dominion (MAD) Subzone was $5.39 per MW in 2018, an increase of $2.11 from 2017.

  The weighted average price for tier 2 synchronized reserve for all cleared hours/intervals in the RTO Synchronized Reserve Zone was $6.15 per MW in 2018, an increase of $2.37 from 2017.

Nonsynchronized Reserve Market

Nonsynchronized reserve is part of primary reserve and includes the RTO Reserve Zone and the Mid-Atlantic Dominion Reserve Subzone (MAD). Nonsynchronized reserve is comprised of nonemergency energy resources not currently synchronized to the grid that can provide energy within 10 minutes. Nonsynchronized reserve is available to fill the primary reserve requirement above the synchronized reserve requirement. Generation owners do not submit supply offers for nonsynchronized reserve. PJM defines the demand curve for nonsynchronized reserve and PJM defines the supply curve based on nonemergency generation resources that are available to provide energy and can start in 10 minutes or less (based on offer parameters), and on the resource opportunity costs calculated by PJM.

Market Structure

- **Supply.** In 2018, the average hourly supply of eligible nonsynchronized reserve was 3,683.2 MW in the RTO Zone.
- **Demand.** Demand for nonsynchronized reserve equals the primary reserve requirement minus the tier 1 synchronized reserve estimate and minus the scheduled tier 2 synchronized reserve.[5] In the RTO Zone, the market scheduled an hourly average of 1,968.8 MW of nonsynchronized reserve in 2018.
- **Market Concentration.** The MMU calculates that the three pivotal supplier test would have failed in 44.8 percent of hours. In 2018, the weighted average HHI for cleared nonsynchronized reserve in the RTO Zone was 4443, which is highly concentrated.

Market Conduct

- **Offers.** Generation owners do not submit supply offers. Nonemergency generation resources that are available to provide energy and can start in 10 minutes or less are considered available for nonsynchronized reserves by the market solution software. PJM calculates the associated offer prices based on PJM calculations of resource specific opportunity costs.

Market Performance

- **Price.** The nonsynchronized reserve price is determined by the opportunity cost of the marginal nonsynchronized reserve unit. The nonsynchronized reserve weighted average price for all hours in the RTO Reserve Zone was $0.29 per MW in 2018. The price cleared above $0.00 in 1.0 percent of hours.

Secondary Reserve

There is no NERC standard for secondary reserve. PJM defines secondary reserve as reserves (online or offline available for dispatch) that can be converted to energy in 30 minutes. PJM defines a secondary reserve requirement but does not have a goal to maintain this reserve requirement in real time.

PJM maintains a day-ahead, offer-based market for 30 minute day-ahead secondary reserve. The Day-Ahead Scheduling Reserve Market (DASR) has no performance obligations except that a unit which clears the DASR market may not be on an outage in real time.[6] If DASR units are on an outage in real time or cleared DASR MW are not available, the DASR payment is not made.

Market Structure

- **Supply.** The DASR Market is a must offer market. Any resources that do not make an offer have their offer set to $0.00 per MW. DASR is calculated by the day-ahead market solution as the lesser of the 30 minute energy ramp rate or the economic maximum MW minus the day-ahead dispatch point for all online units. In 2018, the average available hourly DASR was 39,595.6 MW.
- **Demand.** The DASR requirement for 2018 is 5.28 percent of peak load forecast, down from 5.52 percent in 2017. The average DASR MW purchased in 2018 was 5,690.1 MW per hour, compared to 4,477.3 MW per hour in 2017.
- **Concentration.** In 2018, the DASR Market would have failed the three pivotal supplier test in 9.8 percent of hours.

Market Conduct

- **Withholding.** Economic withholding remains an issue in the DASR Market. The direct marginal cost of providing DASR is zero. PJM calculates the opportunity cost for each resource. All offers by resource owners greater than zero constitute economic withholding. In 2018, a daily average of 38.8 percent of units offered above $0.00. A daily average of 15.8 percent of units offered above $5.
- **DR.** Demand resources are eligible to participate in the DASR Market. Some demand resources have entered offers for DASR. No demand resources cleared the DASR market in 2018.

Market Performance

- **Price.** In 2018, the weighted average DASR price for all hours when the DASRMCP was above $0.00 was $3.49.

5 See PJM. "Manual 11: Energy & Ancillary Services Market Operations," § $b.2.2 Non-Synchronized Reserve Zones and Levels, Rev. 104 (February 7, 2019). "Because Synchronized Reserve may be utilized to meet the Primary Reserve requirement, there is no explicit requirement for non-synchronized reserves."

6 See PJM, "Manual 11: Energy & Ancillary Services Market Operations," § 11.2.7 Day-Ahead Scheduling Reserve Performance, Rev. 104 (February 7, 2019).

Regulation Market

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

Market Structure

- **Supply.** In 2018, the average hourly eligible supply of regulation for nonramp hours was 1,125.5 performance adjusted MW (876.2 effective MW). This was a decrease of 10.6 performance adjusted MW (a decrease of 7.1 effective MW) from 2017, when the average hourly eligible supply of regulation was 1,136.1 performance adjusted MW (869.0 effective MW). In 2018, the average hourly eligible supply of regulation for ramp hours was 1,438.3 performance adjusted MW (1,204.1 effective MW). This was an increase of 11.1 performance adjusted MW (an increase of 20.7 effective MW) from 2017, when the average hourly eligible supply of regulation was 1,427.2 performance adjusted MW (1,183.4 effective MW).
- **Demand.** Prior to January 9, 2017, the hourly regulation demand was set to 525.0 effective MW for nonramp hours and 700.0 effective MW for ramp hours. Starting January 9, 2017, the hourly regulation demand was set to 525.0 effective MW for nonramp hours and 800.0 effective MW for ramp hours.
- **Supply and Demand.** The nonramp regulation requirement of 525.0 effective MW was provided by a combination of RegA and RegD resources equal to 483.0 hourly average performance adjusted actual MW in 2018. This is a decrease of 5.1 performance adjusted actual MW from 2017, when the average hourly total regulation cleared performance adjusted actual MW for nonramp hours were 488.1 performance adjusted actual MW. The ramp regulation requirement of 800.0 effective MW was provided by a combination of RegA and RegD resources equal to 749.3 hourly average performance adjusted actual MW in 2018. This is an increase of 29.1 performance adjusted actual MW from 2017, where the average hourly regulation cleared MW for ramp hours were 720.2 performance adjusted actual MW.

  The ratio of the average hourly eligible supply of regulation to average hourly regulation demand (performance adjusted cleared MW) for ramp hours was 1.92 in 2018. This is a decrease of 3.22 percent from 2017, when the ratio was 1.98. The ratio of the average hourly eligible supply of regulation to average hourly regulation demand (performance adjusted cleared MW) for nonramp hours was 2.33 in 2018, unchanged from the ratio in 2017.
- **Market Concentration.** In 2018, the three pivotal supplier test was failed in 81.7 percent of hours. In 2018, the effective MW weighted average HHI of RegA resources was 2419 which is highly concentrated and the weighted average HHI of RegD resources was 1546 which is also highly concentrated.[7] The weighted average HHI of all resources was 1125, which is moderately concentrated.

Market Conduct

- **Offers.** Daily regulation offer prices are submitted for each unit by the unit owner. Owners are required to submit a cost-based offer and may submit a price-based offer. Offers include both a capability offer and a performance offer. Owners must specify which signal type the unit will be following, RegA or

7 HHI results are based on market shares of effective MW, defined as regulation capability MW adjusted by performance score and resource specific benefit factor, consistent with the way the regulation market is cleared.

RegD.[8] In 2018, there were 227 resources following the RegA signal and 69 resources following the RegD signal.

Market Performance

- **Price and Cost.** The weighted average clearing price for regulation was $25.33 per MW of regulation in 2018. This is an increase of $8.55 per MW, or 50.9 percent, from the weighted average clearing price of $16.78 per MW in 2017. The weighted average cost of regulation in 2018 was $31.94 per MW of regulation. This is an increase of $8.90 per MW, or 38.6 percent, from the weighted average cost of $23.04 per MW in 2017.
- **Prices.** RegD resources continue to be incorrectly compensated relative to RegA resources due to an inconsistent application of the marginal benefit factor in the optimization, assignment and settlement processes. If the Regulation Market were functioning efficiently, RegD and RegA resources would be paid the same price per effective MW. RegA resources are paid on the basis of dollars per effective MW of RegA. RegD resources are not paid in terms of dollars per effective MW of RegA because the marginal benefit factor is not used in settlements. When the marginal benefit factor is above 1.0, RegD resources are generally (depending on the mileage ratio) underpaid on a per effective MW basis. When the MBF is less than one, RegD resources are generally overpaid on a per effective MW basis.
- **Marginal Benefit Factor Function.** The marginal benefit factor (MBF) is intended to measure the operational substitutability of RegD resources for RegA resources. The marginal benefit factor function is incorrectly defined and applied in the PJM market clearing. Correctly defined, the MBF function represents the Marginal Rate of Technical Substitution (MRTS) between RegA and RegD. Correctly implemented, the MBF would be consistently applied in the Regulation Market clearing and settlement. The current incorrect and inconsistent implementation of the MBF function has resulted in the PJM Regulation Market over procuring RegD relative to RegA in most hours and in a consistently inefficient market signal to participants regarding the value of RegD to the market in every hour. This over procurement of RegD can also degrade the ability of PJM to control ACE.
- **Changes to the Regulation Market.** The MMU and PJM developed a joint proposal to address the significant flaws in the regulation market design which was approved by the PJM Members Committee on July 27, 2017, and filed with FERC on October 17, 2017. The proposal addresses issues with the inconsistent application of the marginal benefit factor throughout the optimization and settlement process in the PJM Regulation Market. On March 30, 2018, this joint proposal was rejected by FERC.[9] The MMU and PJM have filed requests for rehearing.[10]

Black Start Service

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

In 2018, total black start charges were $64.7 million, including $64.4 million in revenue requirement charges and $0.303 million in operating reserve charges. Black start revenue requirements consist of fixed black start service costs, variable black start service costs, training costs, fuel storage costs, and an incentive factor. Black start operating reserve charges are paid to units scheduled in the Day-Ahead Energy Market or committed in real time to provide black start service under the ALR option or for black start testing. Black start zonal charges in 2018 ranged from $0.07 per MW-day in the DLCO Zone (total charges were $72,167) to $4.26 per MW-day in the PENELEC Zone (total charges were $4,496,206).

Reactive

Reactive service, reactive supply and voltage control are provided by generation and other sources of reactive power (measured in MVAr). Reactive power helps

8 See the *2018 State of the Market Report for PJM*, Vol. 2, Appendix F "Ancillary Services Markets."

9 162 FERC ¶ 61,295.

10 FERC Docket No. ER18-87-002.

11 OATT Schedule 1 § 1.3BB.

maintain appropriate voltage levels on the transmission system and is essential to the flow of real power (measured in MW).

Reactive capability revenue requirements are based on FERC approved filings that permit recovery based on a cost of service approach.[12] Reactive service charges are paid to units that operate in real time outside of their normal range at the direction of PJM for the purpose of providing reactive service. Reactive service charges are paid for scheduling in the Day-Ahead Energy Market and committing units in real time that provide reactive service. In 2018, total reactive charges were $342.0 million, a 3.1 percent increase from $331.7 million in 2017. Reactive capability revenue requirement charges increased from $311.3 million in 2017 to $328.8 million in 2018 and reactive service charges decreased from $20.4 million in 2017 to $13.1 million in 2018. Total reactive service charges in 2018 ranged from $0 in the RECO Zone, which has no generating units, to $50.8 million in the ComEd Zone.

Frequency Response

On February 15, 2018, the Commission issued Order No. 842, which modified the pro forma large and small generator interconnection agreements and procedures to require newly interconnecting generating facilities, both synchronous and non-synchronous, to include equipment for primary frequency response capability as a condition to receive interconnection service.[13] PJM filed revisions in compliance with Order No. 842 that substantively incorporated the pro forma agreements into its market rules.[14]

Ancillary Services Costs per MWh of Load: 1999 through 2018

Table 10-4 shows PJM ancillary services costs for 1999 through 2018, per MWh of load. The rates are calculated as the total charges for the specified ancillary service divided by the total PJM real-time load in MWh. The scheduling, system control, and dispatch category of costs is comprised of PJM scheduling, PJM system control and PJM dispatch; owner scheduling, owner system control and owner dispatch; other supporting facilities; black start services; direct assignment facilities; and ReliabilityFirst Corporation charges. The cost per MWh of load in Table 10-4 is a different metric than the cost of each ancillary service per MW of that service. The cost per MWh of load includes the effects both of price changes per MW of the ancillary service and changes in total load.

Table 10-4 History of ancillary services costs per MWh of Load: 1999 through 2018[15 16]

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

Recommendations

- The MMU recommends that the Regulation Market be modified to incorporate a consistent application of the marginal benefit factor (MBF) throughout the optimization, assignment and settlement process. The MBF should be defined as the Marginal Rate of Technical Substitution (MRTS) between RegA and RegD. (Priority: High. First reported 2012. Status: Not adopted. FERC rejected, pending rehearing request before FERC.[17])
- The MMU recommends that the lost opportunity cost in the ancillary services markets be calculated using the schedule on which the unit was scheduled to run in the energy market. (Priority: High. First

12 OATT Schedule 2.
13 See 157 FERC ¶ 61,122 (2016).
14 See 164 FERC ¶ 61,224 (2018).

15 Note: The totals Table 10-4 account for after the fact billing adjustments made by PJM and may not match totals presented in past reports.
16 Reactive totals include FERC approved rates for reactive capability.
17 FERC Docket No. ER18-87.

reported 2010. Status: Not adopted.[18] FERC rejected, pending rehearing request before FERC.[19])

- The MMU recommends that the lost opportunity cost calculation used in the Regulation Market be based on the resource's dispatched energy offer schedule, not the lower of its price or cost offer schedule. (Priority: Medium. First reported 2010. Status: Not adopted. FERC rejected, pending rehearing request before FERC.[20])
- The MMU recommends that, to prevent gaming, there be a penalty enforced in the Regulation Market as a reduction in performance score and/or a forfeiture of revenues when resource owners elect to deassign assigned regulation resources within the hour. (Priority: Medium. First reported 2016. Status: Not adopted. FERC rejected, pending rehearing request before FERC.[21])
- The MMU recommends enhanced documentation of the implementation of the Regulation Market design. (Priority: Medium. First reported 2010. Status: Not adopted. FERC rejected, pending rehearing request before FERC.[22])
- 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. (Priority: Medium. First reported 2016. Status: Adopted, 2018.)
- The MMU recommends that PJM be required to save data elements necessary for verifying the performance of the Regulation Market. (Priority: Medium. First reported 2010. Status: Not adopted.)
- The MMU recommends that the $7.50 margin be eliminated from the definition of the cost of tier 2 synchronized reserve because it is a markup and not a cost. (Priority: Medium. First reported Q3, 2018. Status: Not adopted.)
- 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. (Priority: High. First reported 2013. Status: Not adopted.)
- The MMU recommends that the tier 2 synchronized reserve must offer requirement be enforced on a daily and hourly basis. The MMU recommends that PJM define a set of acceptable reasons why a unit can be made unavailable daily or hourly and require unit owners to select a reason in Markets Gateway whenever making a unit unavailable either daily or hourly or setting the offer MW to 0 MW. (Priority: Medium. First reported 2013. Status: Partially adopted.)
- 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. (Priority: Medium. First reported 2012. Status: Not adopted.)
- 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. (Priority: Medium. First reported Q3, 2018. Status: Not adopted.)
- The MMU recommends that aggregation not be permitted to offset unit specific penalties for failure to respond to a synchronized reserve event. (Priority: Medium. First reported Q3, 2018. Status: Not adopted.)
- The MMU recommends that PJM eliminate the use of Degree of Generator Performance (DGP) in the synchronized reserve market solution and improve the actual tier 1 estimate. If PJM continues to use DGP, DGP should be documented in PJM's manuals. (Priority: Medium. New recommendation. Status: Not adopted.)
- The MMU recommends that a reason code be attached to every hour in which PJM market

18 This recommendation was adopted by PJM for the Energy Market. Lost opportunity costs in the Energy Market are calculated using the schedule on which the unit was scheduled to run. In the Regulation Market, this recommendation has not been adopted, as the LOC continues to be calculated based on the lower of price or cost in the energy market offer.
19 FERC Docket No. ER18-87.
20 *Id.*
21 *Id.*
22 *Id.*

operations adds additional DASR MW. (Priority: Medium. First reported 2015. Status: Not adopted.)

- The MMU recommends that PJM modify the DASR Market to ensure that all resources cleared incur a real-time performance obligation. (Priority: Low. First reported 2013. Status: Not adopted.)
- The MMU recommends that offers in the DASR Market be based on opportunity cost only in order to eliminate market power. (Priority: Low. First reported 2009. Modified, 2018. Status: Not adopted.)
- The MMU recommends that separate cost of service payments for reactive capability be eliminated and the cost of reactive capability be recovered in the capacity market. (Priority: Medium. First reported 2016. Status: Not adopted.)
- The MMU recommends that payments for reactive capability, if continued, be based on the 0.90 power factor that PJM has determined is necessary. (Priority: Medium. First reported Q3, 2018. Status: Not adopted.)
- 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. (Priority: Medium. New recommendation. Status: Not adopted.)
- The MMU recommends 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 the MTSL will be calculated for black start units sharing oil tanks. (Priority: Medium. First reported 2017. Status: Not adopted.)
- 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. (Priority: Low. First reported 2017. Status: Not adopted.)

Conclusion

The current PJM regulation market design that incorporates two signals using two resource types was a result of FERC Order No. 755 and subsequent orders.[23]

The design of the PJM Regulation Market is significantly flawed. The market design does not correctly incorporate the marginal rate of technical substitution (MRTS) in market clearing and settlement. The market design uses the marginal benefit factor (MBF) to incorrectly represent the MRTS and uses a mileage ratio instead of the MBF in settlement. This failure to correctly and consistently incorporate the MRTS into the regulation market design has resulted in both underpayment and overpayment of RegD resources and in the over procurement of RegD resources in all hours. The market results continue to include the incorrect definition of opportunity cost. These issues are the basis for the MMU's conclusion that the regulation market design is flawed.

To address these flaws, the MMU and PJM developed a joint proposal which was approved by the PJM Members Committee on July 27, 2017, and filed with FERC on October 17, 2017.[24] The PJM/MMU joint proposal addresses issues with the inconsistent application of the marginal benefit factor throughout the optimization and settlement process in the PJM Regulation Market. FERC rejected the joint proposal on March 30, 2018, as being noncompliant with Order No. 755.[25] The MMU and PJM have separately filed requests for rehearing.[26]

The structure of the Tier 2 Synchronized Reserve Market has been evaluated and the MMU has concluded that these markets are not structurally competitive as they are characterized by high levels of supplier concentration and inelastic demand. As a result, these markets are operated with market clearing prices and with offers based on the marginal cost of producing the product plus a margin. As a result of these requirements, the conduct of market participants within these market structures has been consistent with competition, and the market performance results have been competitive. However, the $7.50 margin is not a cost. The margin is effectively a rule-based form of market power and is therefore

23 Order No. 755, 137 FERC ¶ 61,064 at PP 197–200 (2011).
24 18 CFR § 385,211 (2017)
25 162 FERC ¶ 61,295 (2018).
26 The MMU filed its request for rehearing on April 27, 2018, and PJM filed its request for rehearing on April 30, 2018.

not consistent with a competitive outcome. The $7.50 margin should be eliminated. Participant performance has not been adequate. Compliance with calls to respond to actual synchronized reserve events remains less than 100 percent. For the spinning events 10 minutes or longer in 2016, the average tier 2 synchronized reserve response was 85.5 percent of all scheduled MW. For the six spinning events 10 minutes or longer in 2017, the response was 87.6 percent of scheduled tier 2 MW. For the seven spinning events longer than 10 minutes in 2018, the response was 74.2 percent of scheduled tier 2 MW. Actual participant performance implies that the penalty structure is not adequate to incent performance.

The rule that requires payment of the tier 2 synchronized reserve price to tier 1 synchronized reserve resources when the nonsynchronized reserve price is greater than zero, is inefficient and results in a substantial windfall payment to the holders of tier 1 synchronized reserve resources. Tier 1 resources have no obligation to perform and pay no penalties if they do not perform, and tier 1 resources do not incur any costs when they are part of the tier 1 estimate in the market solution. Tier 1 resources are already paid for their response if they do respond. Tier 1 resources require no additional payment. If tier 1 resources wish to be paid as tier 2 resources, the rules provide the opportunity to make competitive offers in the tier 2 market and take on the associated obligations. Overpayment of tier 1 resources based on this rule added $89.7 million to the cost of primary reserve in 2014, $34.1 million in 2015, $4.9 million in 2016, $2.2 million in 2017, and $4.7 million in 2018.

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

The MMU concludes that the regulation market results were competitive, although the market design is flawed. The MMU concludes that the synchronized reserve market results were competitive, although the $7.50 margin should be removed. The MMU concludes that the DASR market results were competitive, although offers above the competitive level continue to affect prices.

Primary Reserve

NERC Performance Standard BAL-002-3, Disturbance Control Standard – Contingency Reserve for Recovery from a Balancing Contingency Event, requires PJM to carry sufficient contingency reserve to recover from a sudden balancing contingency (usually a loss of generation). The Contingency Event Recovery Period is the time required to return the ACE to zero if it was zero or positive before the event or to its pre-event level if it was negative at the start of the event. PJM defines its Contingency Event Recovery Period as 15 minutes and its Contingency Reserve Restoration Period as 90 minutes.[27] The NERC requirement is 100 percent compliance and status must be reported quarterly. PJM implements this contingency reserve requirement using primary reserves.[28] PJM maintains 10 minute reserves (primary reserve) to ensure reliability in the event of disturbances. PJM's primary reserves are made up of resources, both synchronized and nonsynchronized, that can provide energy within 10 minutes.

Market Structure

Demand

PJM requires that 150 percent of the largest contingency on the system be maintained as primary reserve. PJM can make temporary adjustments to the primary reserve requirement when grid maintenance or outages change the largest contingency or in cases of hot weather alerts or cold weather alerts.

The Primary Reserve Market requirement is calculated dynamically for each market solution, ASO, IT SCED, and RT SCED, as 150 percent of the most severe single contingency (MSSC).

PJM can, for conservative operations, raise the primary and synchronized reserve requirement. Such additional reserves are committed as part of the hourly (ASO) and five minute (RTSCED) processes. In 2018, the average five minute interval primary reserve requirement for the

27 See PJM "Manual 12: Balancing Operations," Rev. 39 (Feb. 21, 2019) Attachment D, "the Disturbance Recovery Period is 15 minutes after the start of a Reportable Disturbance. Subsequently, PJM must fully restore the Synchronized Reserve within 90 minutes."

28 See PJM "Manual 10: Pre-Scheduling Operations," § 3.1.1 Day-ahead Scheduling (Operating) Reserve, Rev. 37 (Dec. 10, 2018).

RTO Zone was 2,267.8 MW. The average five minute interval primary reserve requirement in the MAD Subzone was 2,247.3 MW. These averages include the hours when PJM raised the requirements.

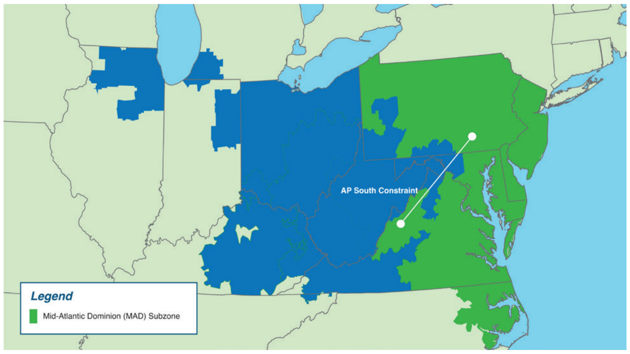
The MMU identified instances when PJM increased the primary and synchronized reserve requirements (see Table 10-5) from their levels prior to and following the identified increases. The amounts of the increases are calculated against average requirement levels before and after the periods of increase.

Table 10-5 Temporary adjustments to primary and synchronized reserve in 2018

From	To	Number of Hours	Amount of Adjustment
8-Jan-18	8-Jan-18	5	Primary reserve (450MW), Synchronized reserve (300MW)
28-Feb-18	3-Mar-18	55	Primary reserve (450MW), Synchronized reserve (300MW)
7-Mar-18	7-Mar-18	5	Primary reserve (450MW), Synchronized reserve (300MW)
15-Mar-18	15-Mar-18	18	Primary reserve (450MW), Synchronized reserve (300MW)
25-Apr-18	25-Apr-18	8	Primary reserve (950MW), Synchronized reserve (1,430MW)
14-Jun-18	14-Jun-18	4	Primary reserve (1,250MW), Synchronized reserve (850MW)
15-Jun-18	15-Jun-18	12	Primary reserve (2,050MW), Synchronized reserve (1,350MW)
18-Jul-18	19-Jul-18	17	Primary reserve (500MW), Synchronized reserve (300MW)
19-Jul-18	20-Jul-18	21	Primary reserve (500MW), Synchronized reserve (300MW)
7-Sep-18	7-Sep-18	2	Primary reserve (1,400MW), Synchronized reserve (950MW)
11-Sep-18	11-Sep-18	12	Primary reserve (1,700MW), Synchronized reserve (1,150MW)
18-Sep-18	18-Sep-18	4	Primary reserve (800MW), Synchronized reserve (500MW)
19-Sep-18	19-Sep-18	4	Primary reserve (650MW), Synchronized reserve (400MW)
20-Sep-18	20-Sep-18	4	Primary reserve (650MW), Synchronized reserve (400MW)
21-Sep-18	21-Sep-18	4	Primary reserve (650MW), Synchronized reserve (400MW)
24-Oct-18	24-Oct-18	10	Primary reserve (200MW), Synchronized reserve (100MW)

Transmission constraints limit the deliverability of reserves within the RTO, requiring the definition of the Mid-Atlantic Dominion (MAD) Subzone (Figure 10-1).[29]

Figure 10-1 PJM RTO Zone and MAD Subzone geography



The most limiting transmission constraint for power flow from the RTO Zone into the MAD Subzone since August, 2017, has been the AP South Interface, which includes Brighton-Conastone, Bedington-Black Oak, Cloverdale-Lexington, and Mt. Storm-Valley.

The NERC standard requires a control area to carry primary reserve MW equal to, or greater than the MSSC.[30] PJM requires primary reserves in the amount of 150 percent of the MSSC with at least 100 percent of the MSSC made up of synchronized reserves. In 2018, the five minute average synchronized reserve requirement in the RTO Zone was 1,577.8 MW. In 2018, the five minute average synchronized reserve requirement in the MAD Subzone was 1,564.3 MW. Beginning July 12, 2017, the synchronized reserve requirement is calculated every five minutes.

Supply

The demand for primary reserve is satisfied by tier 1 synchronized reserves, tier 2 synchronized reserves and nonsynchronized reserves, subject to the requirement that synchronized reserves equal 100 percent of the largest contingency. After the hourly synchronized reserve requirement is satisfied, the remainder of primary reserves is from the least expensive combination of synchronized and nonsynchronized reserves.

Estimated tier 1 is credited against PJM's primary reserve requirement as well as PJM's synchronized reserve requirement. In the MAD Subzone, an average of 1,361.0 MW of tier 1 was identified by the RT SCED market solution as available in 2018 (Table 10-7).[31] Of that 1,361.0 MW, an average of 591.4 MW was available from outside the MAD Subzone. Tier 1 synchronized reserve fully satisfied the MAD Subzone synchronized reserve requirement or reduced the need for tier 2 synchronized reserve to self scheduled reserves in 8.8 percent of intervals in 2018. In the RTO Zone, an average of 1,728.7 MW of tier 1 was available (Table 10-7) fully

29 Additional subzones may be defined by PJM to meet system reliability needs. PJM will notify stakeholders in such an event. See "PJM Manual 11: Energy & Ancillary Services Market Operations," § 4.2.2 Synchronized Reserve Requirement Determination, Rev. 101 (Jan. 9, 2019).

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

31 ASO, Ancillary Services Optimizer. This is the hour-ahead market software that optimizes ancillary services with energy. ASO schedules hourly the Tier 2 Synchronized Reserve, Regulation, and Nonsynchronized Reserves.

satisfying the synchronized reserve requirement in 50.3 percent of intervals.

Regardless of online/offline state, all nonemergency generation capacity resources must submit a daily offer for tier 2 synchronized reserve in Markets Gateway prior to the offer submission deadline (14:15 the day prior to the operating day). Resources listed as available for tier 2 synchronized reserve without a synchronized reserve offer will have their offer price automatically set to $0.00. Offer MW and other non-cost offer parameters can be changed during the operating day. Prior to November 1, 2017, owners were permitted to make resources unavailable for tier 2 synchronized reserve daily or hourly, but only if they were physically unavailable. After November 1, 2017, owners who opt in for intraday updates may change their offer price up to 65 minutes before the hour. Certain unit types including nuclear, wind, solar, and energy storage resources, are expected to have zero MW tier 2 synchronized reserve offer quantities.[32]

After tier 1 is estimated, the remainder of the synchronized reserve requirement is met by tier 2. In the RTO Zone, there were 26,086.3 MW of tier 2 synchronized reserve offered daily. Of this, 7,230.9 MW were located in the MAD Subzone (Figure 10-10) and available to meet the average tier 2 hourly demand of 2,247.3 MW (Table 10-6).

In the MAD Subzone, there was an average of 3,125.9 MW of eligible nonsynchronized reserve supply available to meet the average interval demand for primary reserve. (Table 10-7) In the RTO Zone, an average of 3,677.9 MW supply was available to meet the average interval demand of 2,267.8 MW (Table 10-6).

Table 10-6 provides the average interval reserves, by type of reserve, used by the RT SCED market solution to satisfy the primary reserve requirement in the MAD Subzone from 2017, through 2018.

Table 10-6 Average monthly reserves used to satisfy the primary reserve requirement, MAD Subzone: 2017 through 2018

Year	Month	Tier 1 Total MW	Tier 2 Synchronized Reserve MW	Nonsynchronized Reserve MW	Total Primary Reserve MW
2017	Jan	981.6	356.1	865.7	2,203.5
2017	Feb	1,111.6	233.2	725.3	2,070.1
2017	Mar	767.4	453.3	1,087.8	2,308.5
2017	Apr	896.9	362.4	987.8	2,247.1
2017	May	1,164.6	376.8	933.6	2,475.0
2017	Jun	1,373.0	379.6	808.0	2,560.6
2017	Jul	1,391.9	353.3	801.1	2,546.3
2017	Aug	1,438.3	226.9	759.5	2,424.7
2017	Sep	1,419.2	339.7	786.1	2,545.0
2017	Oct	1,364.2	348.1	913.5	2,625.8
2017	Nov	1,392.1	245.9	825.5	2,463.5
2017	Dec	1,411.5	160.0	816.3	2,387.8
2017		1,226.0	319.6	859.2	2,404.8
2018	Jan	1,371.1	290.4	1,454.0	3,382.4
2018	Feb	1,408.1	264.3	1,461.1	3,504.1
2018	Mar	1,313.3	350.3	1,642.3	3,529.1
2018	Apr	1,192.8	453.7	1,226.4	3,175.5
2018	May	1,191.3	462.4	1,063.7	2,913.2
2018	Jun	1,445.7	185.6	1,195.9	3,239.7
2018	Jul	1,380.1	367.8	1,312.2	3,212.9
2018	Aug	1,334.4	460.1	1,228.5	3,052.2
2018	Sep	1,377.5	383.5	1,007.8	2,916.0
2018	Oct	1,356.5	356.0	602.4	2,705.8
2018	Nov	1,442.4	259.5	798.0	2,813.3
2018	Dec	1,542.6	363.8	1,103.4	3,081.2
2018		1,363.0	349.8	1,174.6	3,127.1

Table 10-7 provides the average monthly reserves, by type of reserve, used by the RT SCED market solution to satisfy the primary reserve requirement in the RTO Zone for January 2017 through December 2018.

32 See PJM "Manual 11: Energy & Ancillary Services Market Operations," § 4.2 PJM Synchronized Reserve Market Business Rules, Rev. 101(Jan. 9, 2019).

Table 10-7 Average monthly reserves used to satisfy the primary reserve requirement, RTO Zone: 2017 through 2018

Year	Month	Tier 1 Total MW	Tier 2 Synchronized Reserve MW	Nonsynchronized Reserve MW	Total Primary Reserve MW
2017	Jan	1,020.4	730.6	1,282.3	2,308.2
2017	Feb	1,172.0	508.3	1,067.0	2,253.2
2017	Mar	654.2	693.1	1,538.6	2,204.0
2017	Apr	805.1	623.0	1,403.6	2,216.5
2017	May	924.1	560.7	1,334.5	2,257.5
2017	Jun	1,413.5	568.8	1,118.7	2,533.0
2017	Jul	1,540.1	667.6	1,131.6	2,675.7
2017	Aug	1,512.8	517.0	1,074.7	2,589.9
2017	Sep	1,368.9	496.6	1,070.3	2,442.3
2017	Oct	1,104.3	528.5	1,338.5	2,971.3
2017	Nov	1,173.6	465.6	1,201.3	2,840.5
2017	Dec	1,308.4	417.8	1,113.1	2,839.3
2017		1,166.4	564.8	1,222.9	2,510.9
2018	Jan	1,792.5	466.6	2,189.8	3,982.2
2018	Feb	1,899.6	379.0	2,207.8	4,107.5
2018	Mar	1,552.4	541.8	2,394.6	3,947.0
2018	Apr	1,034.6	895.0	2,374.9	3,409.5
2018	May	1,318.7	786.6	1,984.7	3,303.3
2018	Jun	2,150.5	344.3	1,927.9	4,078.3
2018	Jul	2,036.8	532.1	1,972.3	4,009.2
2018	Aug	1,948.1	625.8	1,862.3	3,810.3
2018	Sep	1,825.1	602.6	1,717.4	3,542.5
2018	Oct	1,383.0	778.3	1,682.7	3,065.7
2018	Nov	1,596.0	639.6	1,649.7	3,245.6
2018	Dec	1,933.7	587.9	1,722.4	3,656.1
2018		1,705.9	598.3	1,973.9	3,679.8

Supply and Demand

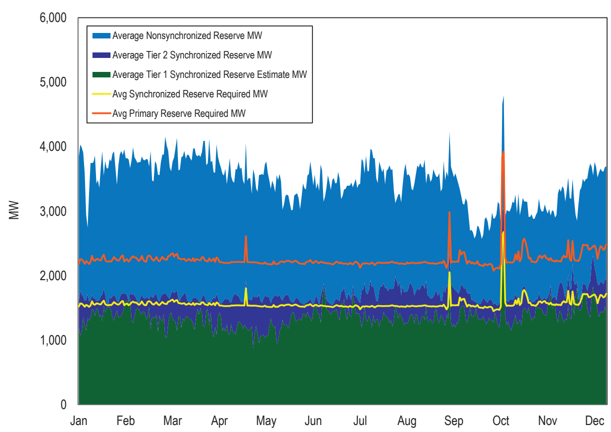
The market solution software relevant to reserves consists of: the Ancillary Services Optimizer (ASO) solving hourly; the intermediate term security constrained economic dispatch market solution (IT SCED); and the real-time (short term) security constrained economic dispatch market solution (RT SCED).

All market solutions determine the actual primary reserves required each hour as one hundred and fifty percent of the largest contingency based on generation and transmission resources. Of this, synchronized reserves must be one hundred percent of the largest contingency. The ASO first assigns self-scheduled synchronized reserves and then estimates the amount of tier 1 synchronized reserves available. The ASO clears inflexible tier 2 synchronized reserve and identifies flexible synchronized reserve sufficient to meet the remaining synchronized reserve requirement.

IT SCED runs at 15 minute intervals and jointly optimizes energy and reserves given the ASO's inflexible unit commitments. IT SCED estimates available tier 1 synchronized reserve and can commit additional reserves (flexibly or inflexibly) if needed. RT SCED runs at five minute intervals and produces load forecasts up to 20 minutes ahead. The RT SCED estimates the available tier 1, provides a real-time ancillary services solution and can commit additional flexible tier 2 resources if needed.

Figure 10-2 illustrates how the ASO satisfied the primary reserve requirement (orange line) for the Mid-Atlantic Dominion Subzone. For the Mid-Atlantic Dominion Reserve Subzone the market solutions must first satisfy the synchronized reserve requirement (yellow line) which is calculated hourly in the MAD Subzone. The market solutions first estimate how much tier 1 synchronized reserve (green area) is available. If there is enough tier 1 MW available to satisfy the synchronized reserve requirement, then they jointly optimize the synchronized reserve and nonsynchronized reserve to assign the remaining primary reserve up to the primary reserve requirement. If there is not enough tier 1 synchronized reserve then the remaining synchronized reserve requirement up to the synchronized reserve is filled with tier 2 synchronized reserve (dark blue area). After synchronized reserve is assigned, the primary reserve requirement is filled by jointly optimizing synchronized reserve and nonsynchronized reserve (light blue area). Since nonsynchronized reserve is priced lower than or equal to synchronized reserve, almost all primary reserve above the synchronized reserve requirement is filled by nonsynchronized reserve.

Figure 10-2 Mid-Atlantic Dominion subzone primary reserve MW by source (Daily Averages): 2018



The solution method is the same for the RTO Reserve Zone.[33] Figure 10-3 shows how the market solutions satisfy the primary reserve requirement for the RTO Zone.

Figure 10-3 RTO reserve zone primary reserve MW by source (Daily Averages): 2018

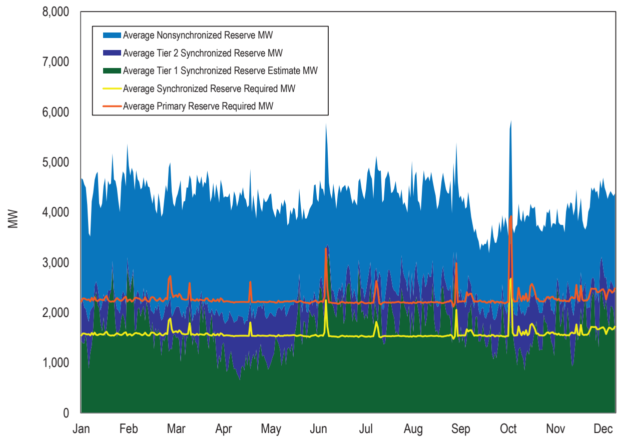


Figure 10-2 shows that within the MAD subzone, Tier 1, Tier 2 from MAD, and Tier 2 from the RTO are all essential to satisfying the synchronized reserve requirement. Figure 10-3 shows that tier 1 synchronized reserve remains the major contributor to satisfying the synchronized reserve requirement in the RTO Zone.

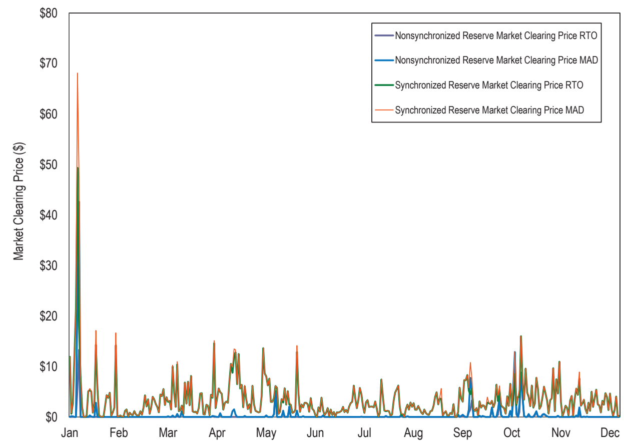
Price and Cost

The price of primary reserves results from the demand curve for primary reserves and the supply of primary reserves. The demand curve is modeled in each of the primary reserve clearing engines (ASO, IT SCED, RT SCED). The demand curve for primary reserves has two steps, with an $850 penalty factor for primary reserve levels ranging from 0 MW to a MW amount equal to 150 percent of the MSSC and a constraint with a $300 penalty factor for primary reserves ranging from 150 percent of MSSC to 150 percent of MSSC plus 190 MW.

The supply of primary reserves is made up of available tier 1 and tier 2 synchronized reserves and non-synchronized reserves. Offer prices for synchronized reserve are capped at $7.50 plus costs plus opportunity costs.

Figure 10-4 shows daily weighted average synchronized and nonsynchronized market clearing prices in the 2018.

Figure 10-4 Daily average market clearing prices ($/MW) for synchronized reserve and nonsynchronized reserve: 2018



PJM's primary reserves are made up of three components, tier 1 synchronized reserve, tier 2 synchronized reserve, and nonsynchronized reserve, each with its own price and cost determinants and interdependent scheduling algorithms. The overall price and cost for meeting the BAL-002-3 primary reserve requirement is calculated by combining the three components. Each of these three components is shown in Table 10-8. The "Cost per MW" column is the total credits divided by the total MW of reserves.

On a combined basis, the ratio of price to cost for all primary reserve during 2018 was 38.8 percent. While tier 1 has zero actual incremental cost, estimated tier 1 is paid the tier 2 clearing price in any hour where nonsynchronized reserves clears at a non-zero price. Table 10-8 shows that the cost of tier 1 reserves is $30.34 per MW when the price of nonsynchronized reserve is greater than zero, or more than three times the cost of tier 2 reserves which is $11.71 per MW.

33 Although tier 1 has a price of zero, changes made with shortage pricing on November 1, 2012, have given tier 1 a very high cost in some hours. This high cost raises questions about the economics of the solution method used by the ASO, IT SCED, and RT SCED market solutions which assume zero cost.

Table 10-8 Primary reserve requirement components, RTO Reserve Zone: 2018

Product	MW Share of Primary Reserve Requirement	MW	Credits Paid	Price Per MW Reserve	Cost Per MW Reserve
Tier 1 Synchronized Reserve Response	NA	15,783	$1,397,244	NA	$88.53
Tier 1 Synchronized Reserve Estimated	1.1%	155,991	$4,732,025	$0.00	$30.34
Tier 2 Synchronized Reserve Scheduled	26.6%	3,684,810	$43,995,208	$6.15	$11.59
Non Synchronized Reserve Scheduled	72.2%	9,991,749	$15,856,155	$0.29	$1.59
Primary Reserve (total of above)	100.0%	13,848,333	$65,980,632	$1.85	$4.76

Tier 1 Synchronized Reserve

Tier 1 synchronized reserve is a component of primary reserve comprised of all online resources following economic dispatch and able to ramp up from their current output in response to a synchronized reserve event. The tier 1 synchronized reserve for a unit is estimated as the lesser of the available 10 minute ramp or the difference between the economic dispatch point and the synchronized reserve maximum output. By default the synchronized reserve maximum for a resource is equal to its economic maximum. Resource owners may request a lower synchronized reserve maximum if a physical limitation exists.[34] Tier 1 resources are identified by the market solution. Tier 1 synchronized reserve has an incremental cost of zero. Tier 1 synchronized reserve is paid under two circumstances. Tier 1 reserves are paid when they respond to a synchronized reserve event. Tier 1 reserves are paid the synchronized reserve market clearing price when the nonsynchronized reserve market clearing price is above $0.

While PJM relies on tier 1 resources to respond to a synchronized reserve event, tier 1 resources are not obligated to respond during an event. Tier 1 resources are credited if they do respond but are not penalized if they do not.

Market Structure

Supply

All generating resources operating on the PJM system with the exception of those assigned to tier 2 synchronized reserve are available for tier 1 synchronized reserve and any response to a spinning event will be credited at the Synchronized Energy Premium Price.

Beginning in January 2015, DGP (Degree of Generator Performance) was introduced as a metric to improve the accuracy of the tier 1 MW estimate used by the market solution. DGP is calculated for all online resources for each market solution. DGP measures how closely the unit has been following economic dispatch for the past 30 minutes. The available tier 1 MW estimated by the market solution for each resource is based upon its economic dispatch, and energy schedule ramp rate or submitted synchronized reserve ramp rate, adjusted by its DGP. PJM communicates to generation operators whose tier 1 MW is part of the market solution the latest estimate of units' tier 1 MW and units' current DGP.[35] DGP should be documented in PJM's Market Rules.

The supply of tier 1 synchronized reserve available to the market solution is adjusted by eliminating tier 1 MW from unit types that cannot reliably provide synchronized reserve. These unit types are nuclear, wind, solar, landfill gas, energy storage, and hydro units.[36] These units will be credited the synchronized energy premium price, like any other responding unit, if they respond to a spinning event. These units will not, however, be paid as tier 1 resources when the nonsynchronized reserve market clearing price goes above $0. There is a review process for resources excluded from the tier 1 estimate that wish to be included.[37]

In 2018, the market solutions estimated tier 1 MW from an average of 151 units that could contribute ramp in a spinning event. The average DGP score was 0.839. In 2018, in the RTO Reserve Zone, the average interval estimated tier 1 synchronized reserve was 1,711.9 MW (Table 10-9). In 60.0 percent of intervals, the estimated tier 1 synchronized reserve was greater than the synchronized reserve requirement, meaning that the synchronized reserve requirement was met entirely by tier 1 synchronized reserve plus self scheduled tier 2.

34 See PJM "Manual 11: Energy & Ancillary Services Market Operations," § 4.2.1 Synchronized Reserve Market Eligibility, Rev. 101 (Jan. 9, 2019).

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

36 See PJM "Manual 11: Energy & Ancillary Services Market Operations," § 4.2.1 Synchronized Reserve Market Eligibility, Rev. 101 (Jan. 9, 2019).

37 See PJM "Manual 11: Energy & Ancillary Services Market Operations," § 4.2.1 Synchronized Reserve Market Eligibility, Rev. 101 (Jan. 9, 2019).

In 2018, the average interval estimated tier 1 synchronized reserve was 1,360.1 MW in the MAD Subzone and 588.2 MW were available from the RTO (Table 10-9). In 17.5 percent of RT SCED intervals, the estimated tier 1 synchronized reserve available within the MAD subzone plus self scheduled tier 2 in MAD was greater than the synchronized reserve requirement. In all other intervals synchronized reserve from the RTO was required to satisfy the requirement.

Table 10-9 Monthly average interval market solutions for tier 1 synchronized reserve (MW): 2017 through 2018

Year	Month	Average Interval Tier 1 Local To MAD	Tier 1 Synchronized Reserve From RTO Zone	Average Interval Tier 1 Used in MAD	Average Interval Tier 1 Used in RTO Zone
2017	Jan	529.3	452.3	981.6	1,020.4
2017	Feb	526.1	585.5	1,111.6	1,172.0
2017	Mar	292.6	474.8	767.4	654.2
2017	Apr	288.2	608.8	896.9	805.1
2017	May	386.5	778.1	1,164.6	924.1
2017	Jun	559.5	813.5	1,373.0	1,413.5
2017	Jul	693.8	698.1	1,391.9	1,540.1
2017	Aug	583.1	855.2	1,438.3	1,512.8
2017	Sep	564.7	854.5	1,419.2	1,368.9
2017	Oct	465.7	898.4	1,364.2	1,104.3
2017	Nov	469.7	922.4	1,392.1	1,173.6
2017	Dec	539.8	871.7	1,411.5	1,308.4
2017		491.6	734.4	1,226.0	1,166.4
2018	Jan	814.2	554.9	1,369.1	1,796.0
2018	Feb	765.6	640.3	1,406.0	1,886.0
2018	Mar	746.1	571.6	1,317.7	1,559.7
2018	Apr	434.1	756.2	1,190.3	1,028.6
2018	May	540.6	654.5	1,195.1	1,340.3
2018	Jun	825.7	613.4	1,439.1	2,113.7
2018	Jul	865.6	509.0	1,374.5	2,058.2
2018	Aug	835.4	493.2	1,328.6	1,923.0
2018	Sep	836.7	540.7	1,377.4	1,805.3
2018	Oct	617.9	737.1	1,355.0	1,393.8
2018	Nov	880.2	566.4	1,446.6	1,611.5
2018	Dec	1,101.1	421.2	1,522.2	2,025.8
2018		771.9	588.2	1,360.1	1,711.9

Demand

There is no required amount of tier 1 synchronized reserve.

The ancillary services market solution treats the cost of estimated tier 1 synchronized reserve as $0, even when the nonsynchronized reserve market clearing price is above $0. As a result, the optimization cannot and does not minimize the total cost of primary reserves. The MMU recommends that tier 1 synchronized reserve not be paid when the nonsynchronized reserve market clearing price is above $0.

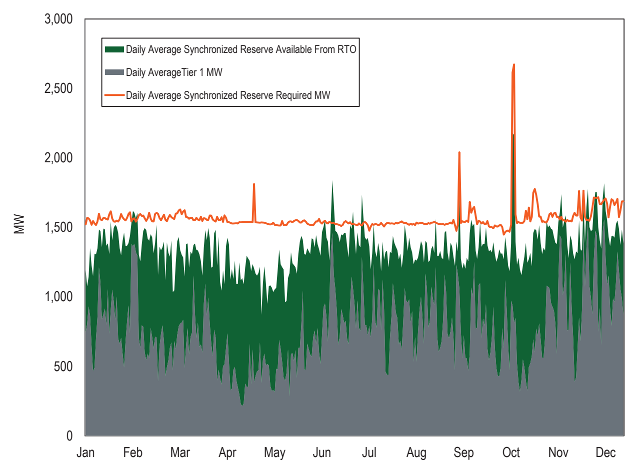
Supply and Demand

The price of synchronized reserves results from the demand curve for synchronized reserves and the supply of synchronized reserves. The demand curve is modeled in each of the synchronized reserve clearing engines (ASO, IT SCED, RT SCED). The demand curve for synchronized reserves has two steps, with an $850 penalty factor for synchronized reserve levels ranging from 0 MW to a MW amount equal to 100 percent of the MSSC and a constraint with a $300 penalty factor for synchronized reserves ranging from 100 percent of MSSC to 100 percent of MSSC plus 190 MW.

When solving for the synchronized reserve requirement the market solution first subtracts the amount of self scheduled synchronized reserve from the requirement and then estimates the amount of tier 1.

In the MAD Subzone, the market solution takes all tier 1 MW estimated to be available within the MAD Subzone (gray area of Figure 10-5) as well as the synchronized reserve MW estimated to be available within the MAD Subzone from the RTO Zone (green area of Figure 10-5) up to the synchronized reserve requirement. If the total tier 1 synchronized reserve is less than the synchronized reserve requirement, the remainder of the synchronized reserve requirement is filled with tier 2 synchronized reserve (white area below the synchronized reserve required line in Figure 10-5).

Figure 10-5 Daily average tier 1 synchronized reserve supply (MW) in the MAD Subzone: 2018



Average demand for synchronized reserve in the RTO Zone in 2018 was 1,577.8 MW, including temporary increases to the requirement.

Tier 1 Synchronized Reserve Event Response

Tier 1 synchronized reserve is awarded credits when a synchronized reserve event occurs and it responds. These synchronized reserve event response credits for tier 1 response are independent of the tier 1 estimated, independent of the synchronized reserve market clearing price, and independent of the nonsynchronized reserve market clearing price. Credits are awarded to tier 1 synchronized reserve resources equal to the increase in MW output (or decrease in MW consumption for demand resources) for each five minute interval times the five minute LMP plus $50 per MW. During a synchronized reserve event, tier 1 credits are awarded to all units that increase their output during the event regardless of their estimated tier 1 MW, or tier 1 deselection status at market clearing time, unless the units have cleared the tier 2 market. Spinning event response is calculated as the highest output between 9 minutes and 11 minutes after the event is declared minus the lowest output between 1 minute before and 1 minute after the event is declared. Total response credited to a resource is capped at 110 percent of estimated capability.

In 2018, tier 1 synchronized reserve spinning event response credits of $1,397,244 were paid for an average response of 620 MWh of tier 1 response at an average cost per MWh of $88.53, over 18 spinning event hours (Table 10-10).

Table 10-10 Tier 1 synchronized reserve event response costs: 2017 through 2018

		Synchronized Reserve Events			Hours When NSRMCP>$0		
Year	Month	Total MWh	Total Credits	Average MWh Per Event	Total MWh	Total Credits	Average MW Per Hour
2017	Jan	1,252	$60,319	208	19,441	$221,157	1,143.6
2017	Feb	627	$56,103	209	1,293	$15,971	1,293.2
2017	Mar	769	$56,352	385	13,389	$191,084	956.4
2017	Apr	308	$17,559	149	11,680	$114,662	730.0
2017	May	389	$20,940	406	20,242	$214,816	1,065.4
2017	Jun	612	$28,681	312	7,563	$37,542	945.4
2017	Jul	0	$0	NA	6,631	$196,128	947.2
2017	Aug	0	$0	NA	3,926	$55,108	981.5
2017	Sep	1,043	$231,178	368	21,030	$948,664	808.9
2017	Oct	0	$0	NA	6,343	$48,539	704.8
2017	Nov	0	$0	NA	24,218	$153,842	931.4
2017	Dec	0	$0	NA	1,274	$295	637.0
2017		5,000	$471,132	291	137,030	$2,197,809	928.7
2018	Jan	6,082	$1,146,858	676	39,047	$2,394,953	1,259.6
2018	Feb	0	$0	NA	0	NA	NA
2018	Mar	0	$0	NA	9,906	$176,651	990.6
2018	Apr	287	$14,969	534	2,584	$48,880	143.6
2018	May	0	$0	NA	5,565	$191,459	347.8
2018	Jun	1,422	$71,416	1,422	3,545	$20,354	590.9
2018	Jul	1,512	$76,588	519	1,763	$4,888	440.7
2018	Aug	534	$26,716	534	1,380	$15,568	460.1
2018	Sep	1,027	$53,492	513	18,256	$478,289	553.2
2018	Oct	144	$7,205	144	60,896	$1,212,173	609.0
2018	Nov	0	$0	NA	12,278	$184,777	341.1
2018	Dec	0	$0	NA	770	$4,034	192.5
2018		11,008	$1,397,244	620	155,991	$4,732,025	539.0

Paying Tier 1 the Tier 2 Price

Tier 1 synchronized reserve has zero marginal cost and the corresponding competitive price for tier 1 synchronized reserves is also zero. However, the PJM rules artificially create a marginal cost of tier 1 when the price of nonsynchronized reserve is greater than zero and tier 1 is paid the tier 2 price. The PJM market solutions do not include that marginal cost and therefore do not solve for the efficient level of tier 1, tier 2 and nonsynchronized reserve in those cases. When called to respond to a spinning event, tier 1 is compensated at the Synchronized Energy Premium Price (Table 10-12). However, the shortage pricing tariff changes (October 1, 2012) modified the pricing of tier 1 so that tier 1 synchronized reserve is paid the tier 2 synchronized reserve market clearing price whenever the nonsynchronized reserve market clearing price rises above zero. The rationale for this change was and is unclear, but it has had a significant impact on the cost of tier 1 synchronized reserves (Table 10-11). The nonsynchronized reserve market clearing price was above $0.00 in 261 hours in 2018. For those 261 hours, tier 1 synchronized reserve resources were paid a weighted average synchronized reserve market clearing price of $19.88 per MWh and earned $4,732,025 in credits.

Table 10-11 Price of tier 1 synchronized reserve attributable to a nonsynchronized reserve price above zero: 2017 through 2018

Year	Month	Total Hours When NSRMCP>$0	Weighted Average SRMCP for Hours When NSRMCP>$0	Total Tier 1 MWh Credited for Hours When NSRMCP>$0	Total Tier 1 Credits Paid When NSRMCP>$0	Average Tier 1 MWh Paid
2017	Jan	17	$11.38	19,441	$221,157	1,143.6
2017	Feb	1	$12.35	1,293	$15,971	1,293.2
2017	Mar	14	$14.27	13,389	$191,084	956.4
2017	Apr	16	$9.82	11,680	$114,662	730.0
2017	May	19	$10.61	20,242	$214,816	1,065.3
2017	Jun	8	$4.96	7,563	$37,542	945.4
2017	Jul	7	$29.58	6,631	$196,128	947.2
2017	Aug	4	$14.04	3,926	$55,108	981.5
2017	Sep	26	$45.11	21,030	$948,664	808.9
2017	Oct	9	$7.65	6,343	$48,539	704.8
2017	Nov	26	$6.35	24,218	$153,842	931.4
2017	Dec	2	$0.26	1,274	$295	637.0
2017		149	$13.87	137,030	$2,197,809	928.7
2018	Jan	31	$61.34	39,047	$2,394,953	1,259.6
2018	Feb	0	NA	NA	NA	NA
2018	Mar	10	$17.83	9,906	$176,651	990.6
2018	Apr	18	$18.91	2,584	$48,880	143.6
2018	May	16	$34.41	5,565	$191,459	347.8
2018	Jun	6	$5.74	3,545	$20,354	590.9
2018	Jul	4	$2.77	1,763	$4,888	440.7
2018	Aug	3	$11.27	1,380	$15,568	460.1
2018	Sep	33	$26.20	18,256	$478,289	553.2
2018	Oct	100	$19.91	60,896	$1,212,173	609.0
2018	Nov	36	$15.05	12,278	$184,777	341.1
2018	Dec	4	$5.24	770	$4,034	192.5
2018		261	$19.88	155,991	$4,732,026	539.0

The additional payments to tier 1 synchronized reserves under the shortage pricing rule are a windfall. The additional payment does not create an incentive to provide more tier 1 synchronized reserves. The additional payment is not a payment for performance; all estimated tier 1 receives the higher payment regardless of whether they provide any response during any spinning event. Tier 1 resources are not obligated to respond to synchronized reserve events. In 2018, 67.2 percent of the DGP adjusted market solution's estimated tier 1 MW actually responded during synchronized reserve events of 10 minutes or longer while 32.8 percent of DGP adjusted tier 1 estimated MW did not respond during spinning events. For all tier 1 units, 76.1 percent of responded with 100 percent of their T1 capability and 9.9 percent of DGP estimated T1 units did not respond at all (zero percent). The remaining 14.0 percent responded with less than their full DGP estimated tier 1 MW. However, all resources that were included in the Tier 1 estimates were paid the Tier 2 price for their full estimated MW when the nonsynchronized reserve (NSR) price was greater than zero. Unlike tier 1 resources, tier 2 synchronized reserve resources are paid the market clearing price for tier 2 because they stand ready to respond and incur costs to do so, have an obligation to perform and pay penalties for nonperformance.

When the next MW of nonsynchronized reserve required to satisfy the primary reserve requirement increases in price from $0.00 per MW to $0.01 per MW, the cost of all tier 1 MW increases significantly.

In 2018, tier 1 synchronized reserve was paid $1,397,244 for responding to synchronized reserve events. During the same time period, tier 1 synchronized reserve was paid a windfall of $4,732,025 simply because the NSRMCP was greater than $0.00 in 261 hours during 2018. Table 10-10 provides a comparison of the cost of Tier 1 as used for spinning events and the cost when compensated because the NSRMCP was greater than $0.

The MMU recommends that the rule requiring the payment of tier 1 synchronized reserve resources when the nonsynchronized reserve price is above zero be eliminated immediately.[38] Tier 1 should be compensated only for a response to synchronized reserve events, as it was before the shortage pricing changes. This compensation requires that when a synchronized reserve event is called, all tier 1 response is paid the average of five-minute LMPs during the event, rather than hourly integrated LMP, plus $50/MW, termed the synchronized energy premium price.

PJM's current tier 1 compensation rules are presented in Table 10-12.

Table 10-12 Tier 1 compensation as currently implemented by PJM

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

The MMU's recommended compensation rules for tier 1 MW are in Table 10-13.

Table 10-13 Tier 1 compensation as recommended by MMU

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

Tier 1 Estimate Bias

PJM's market solution software allows the dispatcher to bias the tier 2 synchronized reserve solution by forcing the software to assume a different tier 1 MW value than it actually estimates. PJM no longer allows dispatchers to use tier 1 biasing in the intermediate and real-time SCED solutions, but tier 1 biasing is used in the hour ahead reserve market solution, ASO. Biasing means manually modifying (decreasing or increasing) the tier 1 synchronized reserve estimate of the market solution. This forces the market clearing engine to clear more or less tier 2 synchronized reserve and nonsynchronized reserve to satisfy the synchronized reserve and primary reserve requirements than would have cleared under the market solution. Negative biasing is the primary form of biasing actually used although sometimes the solution is biased positively (Table 10-14).

Table 10-14 RTO zone ASO tier 1 estimate biasing: 2017 through 2018

Year	Month	Number of Hours Biased Negatively	Average Negative Bias (MW)	Number of Hours Biased Positively	Average Positive Bias (MW)
2017	Jan	332	(987.7)	4	362.5
2017	Feb	194	(719.7)	0	NA
2017	Mar	354	(760.5)	3	200.0
2017	Apr	227	(697.1)	0	NA
2017	May	301	(1,000.3)	13	207.7
2017	Jun	253	(873.5)	0	NA
2017	Jul	244	(938.1)	0	NA
2017	Aug	179	(805.3)	2	1,250.0
2017	Sep	144	(682.6)	0	NA
2017	Oct	234	(807.7)	0	NA
2017	Nov	240	(739.7)	0	NA
2017	Dec	273	(920.0)	0	NA
2017		2,975	(827.7)	22	256.7
2018	Jan	209	(851.9)	0	NA
2018	Feb	85	(558.8)	0	NA
2018	Mar	72	(477.8)	0	NA
2018	Apr	232	(510.6)	0	NA
2018	May	114	(394.1)	4	237.5
2018	Jun	95	(534.5)	3	733.3
2018	Jul	46	(1,716.3)	2	1,600.0
2018	Aug	139	(591.4)	0	NA
2018	Sep	92	(886.2)	2	325.0
2018	Oct	84	(547.6)	0	NA
2018	Nov	40	(666.3)	3	566.7
2018	Dec	20	(1,112.5)	0	NA
2018		1,228	(737.3)	14	692.5

Tier 1 biasing is not mentioned in the PJM manuals and does not appear to be defined in any public document. PJM dispatchers use tier 1 biasing to compensate for uncertainty in short-term load forecasting and uncertainty about expected generator performance, which result in uncertainty about the accuracy of the market solution's tier 1 estimate. The purpose of tier 1 estimate biasing is to modify the demand for tier 2 and therefore the market results both for tier 2 synchronized reserve and for nonsynchronized reserve. Biasing the tier 1 estimate forces the market solution to clear more or less tier 2 and thus affects the price for tier 2 reserves. 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

38 This recommendation was presented as a proposal, "Tier 1 Compensation," to the Markets and Reliability Committee Meeting, October 22, 2015. The MMU proposal and a PJM counterproposal were both rejected.

1 biasing and identify the rule based reasons for each instance of biasing.

Tier 2 Synchronized Reserve Market

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

Synchronized reserve resources can be flexible or inflexible. Inflexible resources are defined as those resources that require an hourly commitment due to minimum run times or staffing constraints. Examples of inflexible reserves are synchronous condensers operating in a condensing mode and demand resources. Tier 2 synchronized reserve resources committed for a full hour by the hour ahead market solution are defined to be inflexible resources. Inflexible resources cannot be released for energy during the operating hour. The inflexible commitments made by the hour ahead ASO solution may satisfy only part of the full tier 2 requirement. The actual requirement is determined every five minutes by the RT SCED solution and the requirement not satisfied by inflexible units is satisfied by flexible units for the interval.

During the operating hour, the IT SCED and the RT SCED market solutions software can dispatch additional resources flexibly. A flexible commitment is one in which the IT SCED or RT SCED redispatches online tier 1 generating resources as tier 2 synchronized reserve to meet the synchronized and primary reserve requirements within the operational hour. Resources that are redispatched as tier 2 within the hour are required to maintain their available ramp and are paid the SRMCP plus any lost opportunity costs or energy use costs that exceed the SRMCP.

Market Structure

Supply

PJM has a must offer tier 2 synchronized reserve requirement. All nonemergency generating resources are required to submit tier 2 synchronized reserve offers. All online, nonemergency generating resources are deemed available to provide both tier 1 and tier 2 synchronized reserve although certain unit types are exempt. If PJM issues a primary reserve warning, voltage reduction warning, or manual load dump warning, all offline emergency generation capacity resources available to provide energy must submit an offer for tier 2 synchronized reserve.[39]

In 2018, the Mid Atlantic Dominion (MAD) Reserve Subzone averaged 7,286.8 MW of tier 2 synchronized reserve offers, and the RTO Reserve Zone averaged 26,161.0 MW of tier 2 synchronized reserve offers (Figure 10-10).

The supply of tier 2 synchronized reserve in 2018 was sufficient to cover the ASO hourly requirement net of tier 1 in both the RTO Reserve Zone and the MAD Reserve Subzone.

The largest portion of cleared tier 2 synchronized reserve in 2018 was from CTs, 54.0 percent (Figure 10-6). Although demand resources are limited to 33 percent of the total synchronized reserve requirement, the amount of tier 2 synchronized reserve required in any hour is often much less than the full synchronized reserve requirement because so much of it is met with tier 1 synchronized reserve. This means that in many hours demand resources make up considerably more than 33 percent of the cleared Tier 2 MW. DR MW were 24.5 percent of cleared Tier 2 Synchronized Reserve Market

39 See PJM "Manual 11: Energy & Ancillary Services Market Operations," § 4.2.1 Synchronized Reserve Market Eligibility, Rev. 101 (Jan. 9, 2019).

in 2018, combined cycle units were 10.8 percent and hydro resources were 7.5 percent.

Figure 10-6 Cleared tier 2 synchronized reserve average MW per hour by unit type, RTO Zone: 2016 through 2018

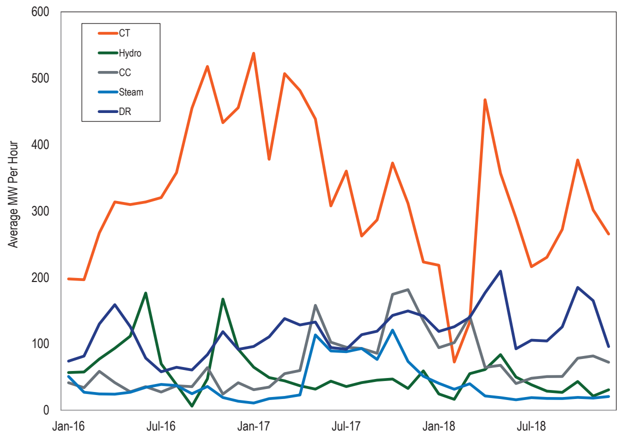
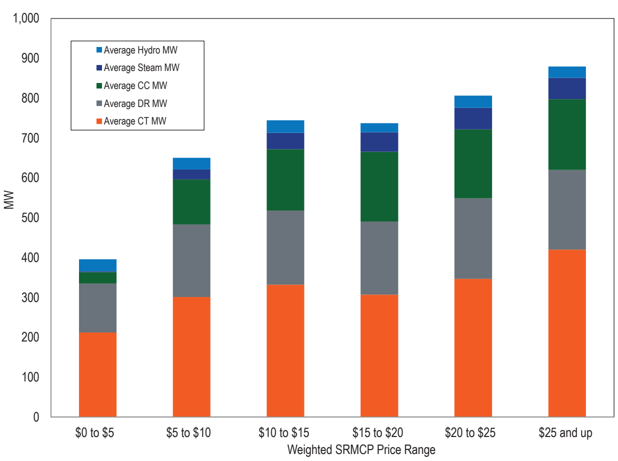


Figure 10-7 provides the average hourly cleared tier 2 MW by unit type by tier 2 clearing price range (SRMCP).

Figure 10-7 Average hourly tier 2 MW by unit type by weighted SRMCP range: January through December, 2018



Demand

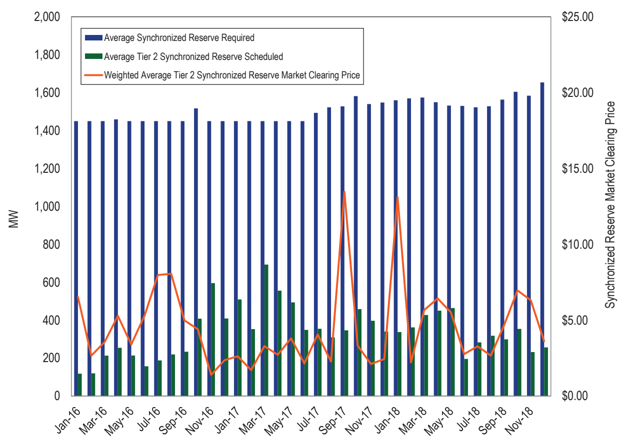
On July 12, 2017, PJM adopted a dynamic synchronized reserve requirement set equal to 100 percent of the largest contingency, determined by the hourly market solution (ASO), based on the forecasted dispatch. There are two circumstances in which PJM may alter the synchronized reserve requirement from its 100 percent of the largest contingency value. When PJM operators anticipate periods of high load, they may bring on additional units to account for increased operational uncertainty in meeting load. When a Hot Weather Alert, Cold Weather Alert or an emergency procedure (as defined in Manual 11 § 4.2.2 Synchronized Reserve Requirement Determination) has been issued for the operating day, operators may increase the synchronized reserve requirement up to the full amount of the additional MW brought on line.[40]

In 2018, the average synchronized reserve requirement per interval in the RTO Zone was 1,577.8 MW and the average synchronized reserve requirement in the MAD Subzone was 1,564.3 MW. These averages include temporary increases to the synchronized reserve requirement.

The RTO Reserve Zone purchased an interval average of 598.4 MW of tier 2 synchronized reserves in 2018. Of this, an average of 352.4 MW cleared within the MAD Subzone.

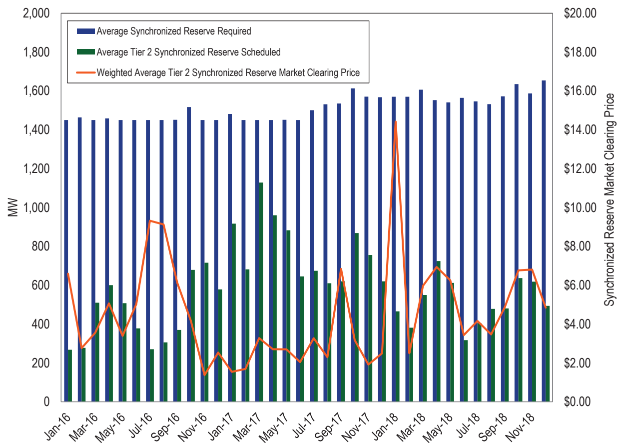
Figure 10-8 and Figure 10-9 show the average monthly synchronized reserve required and the average monthly tier 2 synchronized reserve MW scheduled (PJM scheduled plus self scheduled) from January 2016 through December 2018, for the RTO Reserve Zone and MAD Reserve Subzone. There were three intervals of shortage in 2018. There were 18 spinning events in 2018.

Figure 10-8 MAD hourly average tier 2 synchronized reserve scheduled MW: 2016 through 2018



40 PJM "Manual 11: Energy & Ancillary Services Market Operations," § 4.2.2 Synchronized Reserve Requirement Determination, Rev. 101 (Jan. 9, 2019).

Figure 10-9 RTO hourly average tier 2 synchronized reserve scheduled MW: 2016 through 2018



Market Concentration

The average HHI for tier 2 synchronized reserve cleared intervals in the Mid-Atlantic Dominion Subzone Tier 2 Synchronized Reserve Market in 2018 was 4255, which is defined as highly concentrated. In 68.4 percent of all cleared intervals the maximum market share greater than or equal to 40 percent.

The average HHI for tier 2 synchronized reserve for cleared intervals of the RTO Zone Tier 2 Synchronized Reserve Market in 2018 was 5007, which is defined as highly concentrated. In 84.0 percent of cleared intervals there was a maximum market share greater than or equal to 40 percent.

In the MAD Subzone, flexible synchronized reserve was 2.5 percent of all tier 2 synchronized reserve in 2018. In the RTO Zone, flexible synchronized reserve assigned was 13.1 percent of all tier 2 synchronized reserve during the same period.

In 2018 22.3 percent of hours would have failed the three pivotal supplier test in the MAD Subzone in 2018 for all cleared hours of the inflexible Synchronized Reserve Market in the hour ahead market (Table 10-15) and 10.2 percent of hours would have failed the three pivotal supplier test in the RTO Zone during the same time period.

Table 10-15 Three pivotal supplier test results for the RTO Zone and MAD Subzone: 2017 through 2018

Year	Month	Mid Atlantic Dominion Reserve Subzone Pivotal Supplier Hours	RTO Reserve Zone Pivotal Supplier Hours
2017	Jan	79.3%	67.0%
2017	Feb	73.8%	57.6%
2017	Mar	72.6%	38.3%
2017	Apr	75.0%	51.0%
2017	May	70.9%	69.8%
2017	Jun	62.6%	84.9%
2017	Jul	57.3%	69.5%
2017	Aug	34.8%	71.0%
2017	Sep	53.7%	66.4%
2017	Oct	72.8%	38.5%
2017	Nov	71.2%	47.4%
2017	Dec	75.9%	45.1%
2017		66.7%	58.9%
2018	Jan	65.5%	19.5%
2018	Feb	31.4%	0.0%
2018	Mar	41.2%	13.6%
2018	Apr	17.4%	9.2%
2018	May	15.2%	6.6%
2018	Jun	16.0%	9.3%
2018	Jul	15.4%	11.2%
2018	Aug	13.6%	7.0%
2018	Sep	17.3%	8.3%
2018	Oct	10.6%	11.2%
2018	Nov	16.0%	15.1%
2018	Dec	8.5%	11.6%
2018		22.3%	10.2%

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

Market Behavior

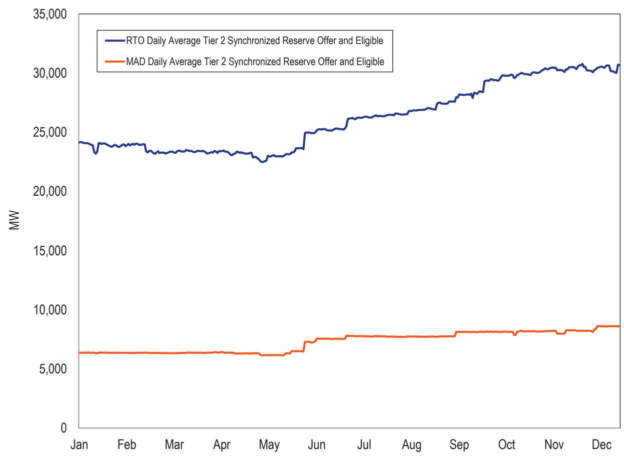
Offers

Daily cost-based offers are submitted for each unit by the unit owner. For generators the offer must include when relevant a tier 1 synchronized reserve ramp rate, a tier 1 synchronized reserve maximum, self scheduled status, synchronized reserve availability, synchronized reserve offer quantity (MW), tier 2 synchronized reserve offer price, energy use for tier 2 condensing resources (MW), condense to gen cost, shutdown costs, condense startup cost, condense hourly cost, condense notification time, and spin as a condenser status. The synchronized reserve offer price made by the unit owner is subject to an offer cap of marginal cost plus a markup of $7.50 per MW. The tier 1 synchronized reserve ramp rate must be greater than or equal to the real-time economic ramp rate. If the synchronized reserve ramp rate is greater than the economic ramp rate it must be justified by the submission of actual data from previous synchronized reserve events.[41] All suppliers are paid the higher of the market clearing price or their offer plus their unit specific opportunity cost. The offer quantity is limited to the economic maximum. PJM monitors this offer by checking to ensure that all offers are greater than or equal to 90 percent of the resource's ramp rate times 10 minutes. A resource that is unable to participate in the synchronized reserve market during a given hour may set its hourly offer to 0.00 MW. Certain defined resource types are not required to offer tier 2 because they cannot reliably provide synchronized reserve. These include: nuclear, wind, solar, landfill gas and energy storage resources.[42]

Figure 10-10 shows the daily average of hourly offered tier 2 synchronized reserve MW for both the RTO Synchronized Reserve Zone and the Mid-Atlantic Dominion Synchronized Reserve Subzone. In 2018, the ratio of eligible tier 2 synchronized reserve to synchronized reserve required in the Mid-Atlantic Dominion Subzone was 4.8 averaged over all hours. For the RTO Synchronized Reserve Zone the ratio was 9.5.

PJM has a tier 2 synchronized reserve must offer requirement for all generation that is online, nonemergency, and physically able to operate with an output less than dictated by economic dispatch. Tier 2 synchronized reserve offers are made on a daily basis with hourly updates permitted. Daily offers can be changed as a result of maintenance status or physical limitations only and are required regardless of online/offline state.[43] The Tier 2 Synchronized Reserve Market is not actually cleared based on daily offers but based on hourly updates to the daily offers. As a result of hourly updates the actual amount of eligible tier 2 MW can change significantly every hour (Figure 10-10). Changes to the hourly offer status are only permitted when resources are physically unable to provide tier 2. Changes to hourly eligibility levels are the result of online status, minimum/maximum runtimes, minimum notification times, maintenance status and grid conditions including constraints. However, resource operators can make their units unavailable for an hour or block of hours without having to provide a reason.

Figure 10-10 Tier 2 synchronized reserve hourly offer and eligible volume (MW): 2018



While over 97 percent of resources have tier 2 synchronized reserve offers, there remain a large number of hours when many units make themselves unavailable for tier 2 synchronized reserve.

The MMU recommends that the tier 2 synchronized reserve must offer requirement be enforced. 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.[44]

Figure 10-11 shows average offer MW volume by market and unit type for the MAD Subzone and Figure 10-12 shows average offer MW volume by market and unit type for the RTO Zone.

41 See PJM "Manual 11: Energy & Ancillary Services Market Operations," § 4.2.1 Synchronized Reserve Market Eligibility Rev. 101 (Jan. 9, 2019).

42 See PJM "Manual 11: Energy & Ancillary Services Market Operations," § 4.2.1 Synchronized Reserve Market Eligibility Rev. 101 (Jan. 9, 2019).

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

44 PJM adopted a new business rule in the third quarter of 2017 to enforce compliance with the tier 2 must-offer requirement. PJM enters a zero dollar offer price for all units with a must offer obligation for tier 2 synchronized reserves.

Figure 10-11 MAD average daily tier 2 synchronized reserve offer by unit type (MW): 2016 through 2018

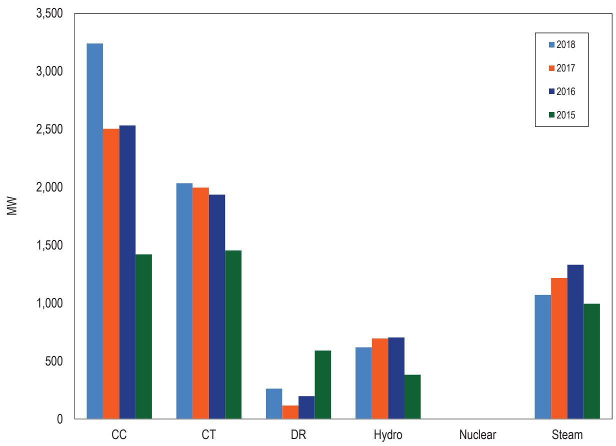
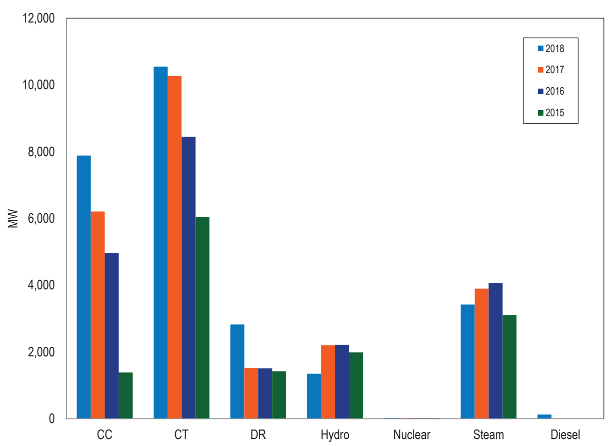


Figure 10-12 RTO Zone average daily tier 2 synchronized reserve offer by unit type (MW): January 2015 through December 2018



Market Performance

Price

The price of tier 2 synchronized reserve is calculated in real time every five minutes for the RTO Reserve Zone and the MAD Subzone. In hours where total tier 1 MW synchronized reserve MW is less than the synchronized reserve requirement, PJM must clear a Tier 2 Synchronized Reserve Market for synchronized reserves.

In 2018, the Tier 2 Synchronized Reserve Market was cleared in 98.6 percent of hours. In the remaining hours and intervals there was enough tier 1 synchronized reserve or self-scheduled tier 2 reserve to cover the full requirement. For 2018 the MAD tier 2 market cleared an average of 331.5 MW at a weighted average clearing price of $5.39 compared to $3.28 in 2017 (Table 10-16).

In 2018, the Tier 2 Synchronized Reserve Market for the RTO Zone cleared an average of 513.5 MW at a weighted average price of $6.15 compared to $3.73 in 2017 (Table 10-17).

In 97.9 percent of cleared hours, the synchronized reserve market clearing price was the same for both the MAD Subzone and the RTO Zone. In the 2.1 percent of hours when the price diverged, the average clearing price was $25.60 in the MAD Subzone, and $14.00 in the RTO Zone.

Supply, performance, and demand are reflected in the price of synchronized reserve. (Figure 10-8 and Figure 10-9).

Table 10-16 MAD Subzone, average SRMCP and average scheduled, tier 1 estimated and demand response MW: 2017 through 2018

Year	Month	Weighted Average Synchronized Reserve Market Clearing Price	Average Tier 2 Generation Synchronized Reserve Purchased (MW)	Average Hourly Tier 1 Synchronized Reserve Estimated Hour Ahead (MW)	Average Hourly Demand Response Cleared (MW)
2017	Jan	$2.25	356.1	981.6	96.0
2017	Feb	$1.75	233.2	1,111.6	110.5
2017	Mar	$2.87	453.3	767.4	140.5
2017	Apr	$2.80	362.4	896.9	128.4
2017	May	$3.26	376.8	1,164.6	126.2
2017	Jun	$2.12	379.6	1,373.0	91.3
2017	Jul	$3.24	353.3	1,391.9	89.4
2017	Aug	$2.05	226.9	1,438.3	110.2
2017	Sep	$11.56	339.7	1,419.2	113.1
2017	Oct	$2.98	348.1	1,364.2	138.8
2017	Nov	$2.08	245.9	1,392.1	144.3
2017	Dec	$2.38	160.0	1,411.5	139.8
2017		$3.28	319.6	1,226.0	119.0
2018	Jan	$13.10	211.7	1,371.1	125.6
2018	Feb	$2.22	181.4	1,408.1	180.6
2018	Mar	$5.67	271.5	1,313.3	156.0
2018	Apr	$6.58	359.6	1,192.8	90.4
2018	May	$5.62	349.3	1,191.3	114.5
2018	Jun	$2.93	146.3	1,445.7	49.7
2018	Jul	$3.29	223.7	1,380.1	59.1
2018	Aug	$2.83	269.5	1,334.4	48.6
2018	Sep	$4.94	238.0	1,377.5	60.8
2018	Oct	$7.28	277.2	1,356.5	76.6
2018	Nov	$6.91	192.6	1,442.4	39.1
2018	Dec	$3.29	222.9	1,524.4	33.7
2018		$5.39	245.3	1,361.5	86.2

Table 10-17 RTO zone average SRMCP and average scheduled, tier 1 estimated and demand response MW: 2017 through 2018

Year	Month	Weighted Average Synchronized Reserve Market Clearing Price	Average Tier 2 Generation Synchronized Reserve Purchased (MW)	Average Hourly Tier 1 Synchronized Reserve Estimated Hour Ahead (MW)	Average Hourly Demand Response Cleared (MW)
2017	Jan	$2.16	730.6	1,020.4	96.0
2017	Feb	$1.89	508.3	1,172.0	110.5
2017	Mar	$3.81	693.1	654.2	140.5
2017	Apr	$2.89	623.0	805.1	128.4
2017	May	$3.48	560.7	924.1	126.2
2017	Jun	$2.24	568.8	1,413.5	91.3
2017	Jul	$4.15	667.6	1,540.1	89.4
2017	Aug	$2.72	517.0	1,512.8	110.2
2017	Sep	$12.60	496.6	1,368.9	113.1
2017	Oct	$3.55	528.5	1,104.3	138.8
2017	Nov	$2.30	465.6	1,173.6	144.3
2017	Dec	$3.00	417.8	1,308.4	139.8
2017		$3.73	564.8	1,166.5	119.0
2018	Jan	$14.42	348.3	1,792.5	117.4
2018	Feb	$2.50	257.6	1,899.6	123.6
2018	Mar	$5.97	412.0	1,552.5	137.6
2018	Apr	$7.06	633.8	1,034.6	90.4
2018	May	$6.19	498.1	1,318.7	114.0
2018	Jun	$3.38	211.6	2,150.5	106.0
2018	Jul	$4.32	291.6	2,036.8	113.1
2018	Aug	$3.74	355.9	1,948.1	122.1
2018	Sep	$5.63	356.1	1,825.1	124.2
2018	Oct	$7.42	512.7	1,383.0	123.9
2018	Nov	$7.32	451.5	1,596.0	167.0
2018	Dec	$4.38	377.3	2,021.6	116.2
2018		$6.15	392.2	1,728.7	121.3

Cost

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

The full cost of tier 2 synchronized reserve including payments for the clearing price and out of market costs is calculated and compared to the price. The closer the price to cost ratio is to one hundred percent, the more the market price reflects the full cost of tier 2 synchronized reserve. A price to cost ratio close to one hundred percent is an indicator of an efficient synchronized reserve market design.

In 2018, the price to cost (including self scheduled) ratio of the RTO Zone Tier 2 Synchronized Reserve Market averaged 53.2 percent (Table 10-18); the price to cost ratio of the MAD Subzone (Table 10-19) averaged 56.7 percent.

Table 10-18 RTO Zone tier 2 synchronized reserve MW, credits, price, and cost: 2017 through 2018

Zone	Year	Month	Tier 2 Credited MW	Tier 2 Credits	LOC Credits	Weighted Average Synchronized Reserve Market Clearing Price	Tier 2 Synchronized Reserve Cost	Price/ Cost Ratio
RTO Zone	2017	Jan	471,027	$950,682	$2,312,698	$2.02	$6.93	29.1%
RTO Zone	2017	Feb	324,004	$551,835	$1,610,492	$1.70	$6.67	25.5%
RTO Zone	2017	Mar	539,157	$1,772,414	$2,800,782	$3.29	$8.48	38.8%
RTO Zone	2017	Apr	451,226	$1,230,490	$2,400,112	$2.73	$8.05	33.9%
RTO Zone	2017	May	421,808	$1,338,275	$1,954,082	$3.17	$7.81	40.6%
RTO Zone	2017	Jun	287,252	$611,155	$1,670,647	$2.13	$7.94	26.8%
RTO Zone	2017	Jul	320,314	$1,164,520	$2,420,822	$3.64	$11.19	32.5%
RTO Zone	2017	Aug	291,160	$667,933	$1,377,119	$2.29	$7.02	32.7%
RTO Zone	2017	Sep	300,167	$3,021,056	$2,096,255	$10.06	$17.05	59.0%
RTO Zone	2017	Oct	403,226	$1,331,871	$2,601,535	$3.30	$9.75	33.9%
RTO Zone	2017	Nov	345,630	$707,061	$1,695,179	$2.05	$6.95	29.4%
RTO Zone	2017	Dec	346,865	$868,623	$2,027,652	$2.50	$8.35	30.0%
RTO Zone	2017		4,501,834	$14,215,915	$24,967,375	$3.24	$8.85	36.6%
RTO Zone	2018	Jan	251,473	$3,736,516	$3,597,281	$14.86	$29.16	50.9%
RTO Zone	2018	Feb	167,661	$432,250	$475,401	$2.58	$5.41	47.6%
RTO Zone	2018	Mar	305,748	$1,829,286	$955,726	$5.98	$9.11	65.7%
RTO Zone	2018	Apr	513,898	$3,676,407	$2,979,772	$7.15	$12.95	55.2%
RTO Zone	2018	May	424,953	$2,693,398	$3,328,585	$6.34	$14.17	44.7%
RTO Zone	2018	Jun	178,862	$617,449	$1,027,023	$3.45	$9.19	37.5%
RTO Zone	2018	Jul	242,712	$1,063,555	$794,436	$4.38	$7.66	57.2%
RTO Zone	2018	Aug	284,146	$1,071,340	$1,407,424	$3.77	$8.72	43.2%
RTO Zone	2018	Sep	280,391	$1,597,878	$1,418,818	$5.70	$10.76	53.0%
RTO Zone	2018	Oct	437,122	$3,294,095	$1,904,130	$7.54	$11.89	63.4%
RTO Zone	2018	Nov	324,837	$2,417,158	$1,454,718	$7.44	$11.92	62.4%
RTO Zone	2018	Dec	273,007	$1,258,968	$963,595	$4.61	$8.14	56.6%
RTO Zone	2018		3,684,810	$23,688,299	$20,306,909	$6.15	$11.59	53.1%

Table 10-19 MAD subzone tier 2 synchronized reserve MW, credits, price, and cost: 2017 through 2018

Zone	Year	Month	Tier 2 Credited MW	Tier 2 Credits	Weighted Average Synchronized Reserve Market Clearing price	Tier 2 Synchronized Reserve Cost	Price/ Cost Ratio
MAD Subzone	2017	Jan	242,160	$1,821,697	$2.25	$7.52	29.9%
MAD Subzone	2017	Feb	137,103	$1,354,202	$1.75	$9.88	17.7%
MAD Subzone	2017	Mar	328,192	$2,611,457	$2.87	$7.96	36.1%
MAD Subzone	2017	Apr	229,057	$1,780,751	$2.80	$7.77	36.0%
MAD Subzone	2017	May	231,704	$1,960,763	$3.26	$8.46	38.5%
MAD Subzone	2017	Jun	170,078	$1,586,215	$2.12	$9.33	22.7%
MAD Subzone	2017	Jul	193,231	$2,367,906	$3.24	$12.25	26.4%
MAD Subzone	2017	Aug	157,259	$1,269,006	$2.05	$8.07	25.4%
MAD Subzone	2017	Sep	172,568	$3,631,598	$11.56	$21.04	54.9%
MAD Subzone	2017	Oct	217,186	$2,703,322	$2.98	$12.45	23.9%
MAD Subzone	2017	Nov	157,391	$1,350,024	$2.08	$8.58	24.3%
MAD Subzone	2017	Dec	138,151	$1,296,784	$2.25	$9.39	24.0%
MAD Subzone	2017		2,374,080	$23,733,724	$3.27	$10.23	32.0%
MAD Subzone	2018	Jan	246,978	$3,908,791	$13.10	$24.89	52.6%
MAD Subzone	2018	Feb	121,873	$537,031	$2.22	$4.41	50.4%
MAD Subzone	2018	Mar	201,995	$1,548,772	$5.67	$7.67	74.0%
MAD Subzone	2018	Apr	258,116	$3,020,632	$6.58	$11.70	56.2%
MAD Subzone	2018	May	259,906	$3,164,879	$5.62	$12.18	46.1%
MAD Subzone	2018	Jun	100,506	$593,608	$2.93	$5.91	49.5%
MAD Subzone	2018	Jul	158,652	$832,799	$3.29	$5.25	62.7%
MAD Subzone	2018	Aug	195,521	$1,354,403	$2.83	$6.93	40.8%
MAD Subzone	2018	Sep	166,472	$1,204,564	$4.94	$7.24	68.3%
MAD Subzone	2018	Oct	206,868	$2,222,948	$7.28	$10.75	67.8%
MAD Subzone	2018	Nov	136,323	$1,642,482	$6.91	$12.05	57.4%
MAD Subzone	2018	Dec	166,883	$856,328	$3.29	$5.13	64.2%
MAD Subzone	2018		2,220,094	$20,887,236	$5.39	$9.51	56.7%

Compliance

The MMU has identified and quantified the actual performance of scheduled tier 2 synchronized reserve resources when called on to deliver during synchronized reserve events since 2011.[45] When synchronized reserve resources self schedule or clear the Tier 2 Synchronized Reserve Market they are obligated to provide their full scheduled tier 2 MW during a synchronized reserve event. Actual synchronized reserve event response is determined by final output minus initial output where final output is the largest output between 9 and 11 minutes after start of the event, and initial output is the lowest output between one minute before the event and one minute after the event.[46] Tier 2 resources are obligated to sustain their final output for the shorter of the length of the event or 30 minutes. Penalties are assessed for failure of a scheduled tier 2 resource to perform during any synchronized reserve event lasting 10 minutes or longer.

In 2015, there were 21 spinning events of which seven were 10 minutes or longer. In 2016, there were 16 spinning events of which six were 10 minutes or longer. In 2017, there were 16 spinning events, six of which were 10 minutes or longer. In 2018 there were 18 spinning events, of which seven were 10 minutes or longer. The MMU has reported synchronized reserve event response levels and recommended that PJM take action to increase compliance rates. Most resources respond at 100 percent but some resources consistently fail to fully respond.

A tier 2 resource is penalized for all hours in the Immediate Past Interval (IPI) in the amount of MW it falls short of its scheduled MW during an event and for any hour in that day for which it cleared. The penalty period is calculated as the lesser of the average number of days between spinning events over the past two years (IPI) or the number of days since the resource last failed to respond fully. For 2018, PJM uses the average number of days between spinning events from November 2016 through October 2018 which is 19 days. Resource owners are permitted to aggregate the response of multiple units to offset an under response from one unit with an overresponse from a different unit to reduce an under response penalty.

The penalty for a tier 2 resource failing to meet its scheduled obligation during a spinning event involves two components. First, the resource foregoes payment for the MW of under-response for all cleared hours of the day of the event. Second, the resource is charged a penalty in the amount of its MW under-response against all of its cleared hours of synchronized reserve during the Immediate Past Interval (IPI) or since the resource last failed to respond to a spinning event, whichever is less. IPI is calculated yearly on December 1 as the average number of days between spinning events over the past two years. Participants with more than one resource can

45 See *2011 State of the Market Report for PJM*, Vol. 2, Section 9, "Ancillary Services," at 250.

46 See PJM "Manual 11: Energy & Ancillary Services Market Operations," § 4.2.10 Settlements Rev. 101 (Jan. 9, 2019).

aggregate their response from over responders to offset under responders during an event.[47]

The penalty structure for tier 2 synchronized reserve nonperformance is flawed. The current penalty rule structure has a number of design issues which limit its effectiveness in providing an incentive for tier 2 MW to respond to spin events.

Under the current penalty structure it is possible for a resource to not respond to any spin events and yet be paid for providing tier 2. The current penalty structure for tier 2 synchronized reserve nonperformance is not adequate to provide appropriate performance incentives.

Under the current penalty structure nonperformance is only defined for spinning events of 10 minutes or longer. For events of less than 10 minutes, all resources, regardless of actual performance, are considered to have performed perfectly. But the IPI is defined as the number of days between spinning events, regardless of duration. This definition artificially shortens the period since the last requirement to perform. The IPI should be defined as the number of days between spinning events 10 minutes or longer. If only events 10 minutes or longer were considered, the IPI would increase to almost double its current 20 days. Regardless, use of an average IPI is not appropriate. The penalty should be based on the actual time since the last spinning event of 10 minutes or longer during which the resource performed. That is the only way to capture the actual failure to perform of the resource and the only way to provide an appropriate performance incentive.

In addition, allowing an organization to aggregate responses from all online resources is a mistake because it weakens the incentive to perform and creates an incentive to withhold reserves from other resources. The obligation to respond is unit specific. Any potentially offsetting response from an affiliated tier 1 resource should have been included as part of the reserves in the tier 1 estimate. Any potentially offsetting response from a tier 2 resource should have been included in that tier 2 offer.

The MMU recommends that aggregation not be permitted to offset unit specific penalties for failure to respond to a synchronized reserve event.

Based on an analysis of six of the most heavily scheduled resources in the tier 2 synchronized reserve market, the MMU concludes that under the current penalty structure completely unresponsive resources would be paid for providing reserves (Table 10-20). The analysis covered the period from the April 1, 2018, introduction of five minute pricing, through December 31, 2018. For resources that completely fail to respond for all spinning events, resource owners would earn 58.2 percent of what they would earn from a perfect response.

Table 10-20 Tier 2 synchronized reserve market penalties: April 1, 2018, through December 31, 2018

Total Scheduled MWh	Actual Spinning Event Shortfall MWh	Credits for Hypothetical T2 Response of 100%	Credits for Hypothetical T2 Response of 0%	Actual T2 Credits	Actual Credits Under IMM Proposed IPI Change
24,926	609	$1,350,022	$786,492	$1,345,571	$1,343,272

The MMU recommends that 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.

Tier 1 resource owners are paid for the actual amount of synchronized reserve they provide in response to a synchronized reserve event.[48] Tier 2 resource owners are paid for being available but are not paid based on the actual response to a synchronized reserve event. Tier 1 resource owners do not have an obligation to respond and are not penalized for a failure to respond. Tier 2 resource owners are penalized for a failure to respond.

There were six synchronized reserve events of 10 minutes or longer in 2017. For those six events, 12.4 percent of all scheduled tier 2 synchronized reserve MW were not delivered and were penalized (Table 10-21). In 2018, there were seven synchronized reserve events of 10 minutes or longer. Tier 2 synchronized reserve response rate was 74.2 percent.

47 See PJM "Manual 28: Operating Agreement Accounting,"§ 6.3 Charges for Synchronized Reserve, Rev. 81 (Oct. 25, 2018).

48 See *id.* at 98.

Table 10-21 Synchronized reserve events 10 minutes or longer, tier 2 response compliance, RTO Reserve Zone: 2017 through 2018

Spin Event (Day, EPT Time)	Duration (Minutes)	Tier 1 Estimate (MW Adj by DGP)	Tier 1 Response (MW)	Tier 2 Scheduled (MW)	Tier 2 Response (MW)	Tier 2 Penalty (MW)	Tier 1 Response Percent	Tier 2 Response Percent
Mar 23, 2017 06:48	24	926.8	549.6	742.8	559.1	183.7	59.3%	75.3%
Apr 8, 2017 11:53	10	1,222.6	827.2	879.3	828.7	50.6	67.7%	94.2%
May 8, 2017 04:18	10	1,325.6	976.3	335.1	298.5	36.6	73.6%	89.1%
Jun 8, 2017 03:39	10	974.4	726.7	575.7	522.4	53.3	74.6%	90.7%
Sep 4, 2017 20:03	15	476.3	68.1	601.0	563.8	37.2	14.3%	93.8%
Sep 21, 2017 14:15	16	305.8	217.4	1,253.9	1,037.3	216.6	71.1%	82.7%
2017 Average	14	871.9	560.9	731.3	635.0	96.3	60.1%	87.6%
Jan 3, 2018 03:00	13	1,896.7	509.9	112.6	57.6	55.0	26.9%	51.2%
Apr 12, 2018 17:28	10	1,063.3	591.2	464.6	372.5	92.1	55.6%	80.2%
Jun 30, 2018 09:46	11	2,710.1	2,086.2	71.6	56.8	14.8	77.0%	79.3%
Jul 10, 2018 15:45	12	784.3	524.9	494.6	308.8	185.8	66.9%	62.4%
Aug 12, 2018 11:06	11	1,824.5	1,390.4	274.5	229.8	44.7	76.2%	83.7%
Sep 30, 2018 11:29	11	1,430.9	976.4	231.2	216.9	14.3	68.2%	93.8%
Oct 30, 2018 06:40	11	239.7	215.9	607.7	431.5	176.2	90.1%	71.0%
2018 Average	11	1,421.4	899.3	322.4	239.1	83.3	63.3%	74.2%

History of Synchronized Reserve Events

Synchronized reserve is designed to provide relief for disturbances.[49] [50] A disturbance is defined as loss of 1,000 MW of generation and/or transmission resources within 60 seconds. In the absence of a disturbance, PJM dispatchers have used synchronized reserve as a source of energy to provide relief from low ACE. There were five low ACE events in 2017, on January 12, 2017 for 8 minutes, February 13, 2017 for 7 minutes, March 23, 2017 for 24 minutes, June 20, 2017 for 9 minutes, and September 21, 2017 for 16 minutes. There was one low ACE event in 2018. PJM conducted an Apparent Cause Analysis (ACA) of the 13 minute event of July 10, 2018, without reaching a definitive cause. The ACA cited several factors including a frequency drop with an unknown cause and pseudo-tied 800MW unit trip.

The risk of using synchronized reserves for energy or any other non-disturbance reason is that it reduces the amount of synchronized reserve available for a disturbance. Disturbances are unpredictable. Synchronized reserve has a requirement to sustain its output for only up to 30 minutes. When the need is for reserve extending past 30 minutes secondary reserve is the appropriate source of the response. The use of synchronized reserve is an expensive solution during an hour when the hour ahead market solution and reserve dispatch indicated no shortage of primary reserve. PJM's primary reserve levels have been sufficient to recover from disturbances and should remain available in the absence of disturbance.

From January 1, 2010, through December 31, 2018, PJM experienced 226 synchronized reserve events (Table 10-22), approximately 2.1 events per month. During this period, synchronized reserve events had an average duration of 11.9 minutes.

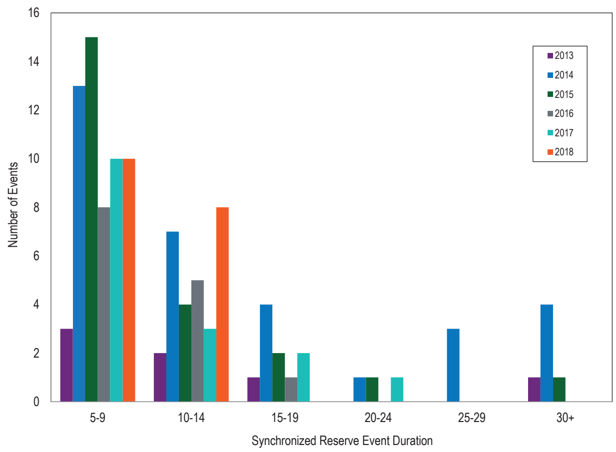
49 *2013 State of the Market Report for PJM*, Appendix F – PJM's DCS Performance, at 451–452.
50 See PJM "Manual 12: Balancing Operations," § 4.1.2 Loading Reserves, Rev. 38 (April 20, 2018).

Table 10-22 Synchronized reserve events: 2010 through 2018

Effective Time	Region	Duration (Minutes)	Effective Time	Region	Duration (Minutes)	Effective Time	Region	Duration (Minutes)	Effective Time	Region	Duration (Minutes)	Effective Time	Region	Duration (Minutes)
FEB-18-2010 13:27	Mid-Atlantic	19	JAN-11-2011 15:10	Mid-Atlantic	6	JAN-03-2012 16:51	RFC	9	JAN-22-2013 08:34	RTO	8	JAN-06-2014 22:01	RTO	68
MAR-18-2010 11:02	RFC	27	FEB-02-2011 01:21	RFC	5	JAN-06-2012 23:25	RFC	8	JAN-25-2013 15:01	RTO	19	JAN-07-2014 02:20	RTO	25
MAR-23-2010 20:14	RFC	13	FEB-08-2011 22:41	Mid-Atlantic	11	JAN-23-2012 15:02	Mid-Atlantic	8	FEB-09-2013 22:55	RTO	10	JAN-07-2014 04:18	RTO	34
APR-11-2010 13:12	RFC	9	FEB-09-2011 11:40	Mid-Atlantic	16	MAR-02-2012 19:54	RFC	9	FEB-17-2013 23:10	RTO	13	JAN-07-2014 11:27	RTO	11
APR-28-2010 15:09	Mid-Atlantic	8	FEB-13-2011 15:35	Mid-Atlantic	14	MAR-08-2012 17:04	RFC	6	APR-17-2013 01:11	RTO	11	JAN-07-2014 13:20	RTO	41
MAY-11-2010 19:57	Mid-Atlantic	9	FEB-24-2011 11:35	Mid-Atlantic	14	MAR-19-2012 10:14	RFC	10	APR-17-2013 20:01	RTO	9	JAN-10-2014 16:46	RTO	12
MAY-15-2010 03:03	RFC	6	FEB-25-2011 14:12	RFC	10	APR-16-2012 00:20	Mid-Atlantic	9	MAY-07-2013 17:33	RTO	8	JAN-21-2014 18:52	RTO	6
MAY-28-2010 04:06	Mid-Atlantic	5	MAR-30-2011 19:13	RFC	12	APR-16-2012 11:18	RFC	8	JUN-05-2013 18:54	RTO	20	JAN-22-2014 02:26	RTO	7
JUN-15-2010 00:46	RFC	34	APR-02-2011 13:13	Mid-Atlantic	11	APR-19-2012 11:54	RFC	16	JUN-08-2013 15:19	RTO	9	JAN-22-2014 22:54	RTO	8
JUN-19-2010 23:49	Mid-Atlantic	9	APR-11-2011 00:28	RFC	6	APR-20-2012 11:08	Mid-Atlantic	7	JUN-12-2013 17:35	RTO	10	JAN-25-2014 05:22	RTO	10
JUN-24-2010 00:56	RFC	15	APR-16-2011 22:51	RFC	9	JUN-20-2012 13:35	RFC	7	JUN-30-2013 01:22	RTO	10	JAN-26-2014 17:11	RTO	6
JUN-27-2010 19:33	Mid-Atlantic	15	APR-21-2011 20:02	Mid-Atlantic	6	JUN-26-2012 17:51	RFC	7	JUL-03-2013 20:40	RTO	13	JAN-31-2014 15:05	RTO	13
JUL-07-2010 15:20	RFC	8	APR-27-2011 01:22	RFC	8	JUL-23-2012 21:45	RFC	18	JUL-15-2013 18:43	RTO	29	FEB-02-2014 14:03	Dominion	8
JUL-16-2010 20:45	Mid-Atlantic	19	MAY-02-2011 00:05	Mid-Atlantic	21	AUG-03-2012 12:44	RFC	10	JUL-28-2013 14:20	RTO	10	FEB-08-2014 06:05	Dominion	18
AUG-11-2010 19:09	RFC	17	MAY-12-2011 19:39	RFC	9	SEP-08-2012 04:34	RFC	12	SEP-10-2013 19:48	RTO	68	FEB-22-2014 23:05	RTO	7
AUG-13-2010 23:19	RFC	6	MAY-26-2011 17:17	Mid-Atlantic	20	SEP-27-2012 17:19	Mid-Atlantic	7	OCT-28-2013 10:44	RTO	33	MAR-01-2014 05:18	RTO	26
AUG-16-2010 07:08	RFC	17	MAY-27-2011 12:51	RFC	6	OCT-17-2012 10:48	RTO	10	DEC-01-2013 11:17	RTO	9	MAR-05-2014 21:25	RTO	8
AUG-16-2010 19:39	Mid-Atlantic	11	MAY-29-2011 09:04	RFC	7	OCT-23-2012 22:29	RTO	19	DEC-07-2013 19:44	RTO	7	MAR-13-2014 20:39	RTO	8
SEP-15-2010 11:20	RFC	13	MAY-31-2011 16:36	RFC	27	OCT-30-2012 05:12	RTO	14				MAR-27-2014 10:37	RTO	56
SEP-22-2010 15:28	Mid-Atlantic	24	JUN-03-2011 14:23	RFC	7	NOV-25-2012 16:32	RTO	12				APR-14-2014 01:16	RTO	10
OCT-05-2010 17:20	RFC	10	JUN-06-2011 22:02	Mid-Atlantic	9	DEC-16-2012 07:01	RTO	9				APR-25-2014 17:33	RTO	6
OCT-16-2010 03:22	Mid-Atlantic	10	JUN-23-2011 23:26	RFC	8	DEC-21-2012 05:51	RTO	7				MAY-01-2014 14:18	RTO	13
OCT-16-2010 03:25	RFCNonMA	7	JUN-26-2011 22:03	Mid-Atlantic	10	DEC-21-2012 10:29	RTO	5				MAY-03-2014 17:11	RTO	13
OCT-27-2010 10:35	RFC	7	JUL-10-2011 11:20	RFC	10							MAY-14-2014 01:36	RTO	5
OCT-27-2010 12:50	Mid-Atlantic	10	JUL-28-2011 18:49	RFC	12							JUL-08-2014 03:07	RTO	9
NOV-26-2010 14:24	RFC	13	AUG-02-2011 01:08	RFC	6							JUL-25-2014 19:19	RTO	7
NOV-27-2010 11:34	RFC	8	AUG-18-2011 06:45	Mid-Atlantic	6							SEP-06-2014 13:32	RTO	18
DEC-08-2010 01:19	RFC	11	AUG-19-2011 14:49	RFC	5							SEP-20-2014 23:42	RTO	14
DEC-09-2010 20:07	RFC	5	AUG-23-2011 17:52	RFC	7							SEP-29-2014 10:08	RTO	15
DEC-14-2010 12:02	Mid-Atlantic	24	SEP-24-2011 15:48	RFC	8							OCT-20-2014 06:35	RTO	15
DEC-16-2010 18:40	Mid-Atlantic	20	SEP-27-2011 14:20	RFC	7							OCT-23-2014 11:03	RTO	27
DEC-17-2010 22:09	Mid-Atlantic	6	SEP-27-2011 16:47	RFC	9							NOV-01-2014 06:50	RTO	9
DEC-29-2010 19:01	Mid-Atlantic	15	OCT-30-2011 22:39	Mid-Atlantic	10							NOV-08-2014 02:08	RTO	8
			DEC-15-2011 14:35	Mid-Atlantic	8							NOV-22-2014 05:27	RTO	21
			DEC-21-2011 14:26	RFC	18							NOV-22-2014 08:19	RTO	10
												DEC-10-2014 18:58	RTO	8
												DEC-31-2014 21:42	RTO	12

Effective Time	Region	Duration (Minutes)	Effective Time	Region	Duration (Minutes)	Effective Time	Region	Duration (Minutes)	Effective Time	Region	Duration (Minutes)
JAN-07-2015 22:36	RTO	8	JAN-18-2016 17:58	RTO	12	JAN-08-2017 03:21	RTO	7	JAN-01-2018 02:41	RTO	7
FEB-24-2015 02:51	RTO	5	FEB-08-2016 15:05	RTO	10	JAN-09-2017 19:24	RTO	9	JAN-03-2018 03:00	RTO	13
FEB-26-2015 15:20	RTO	6	FEB-28-2016 18:29	RTO	8	JAN-10-2017 13:05	MAD	9	JAN-07-2018 14:15	RTO	9
MAR-03-2015 17:02	RTO	11	APR-14-2016 20:09	RTO	10	JAN-15-2017 20:13	RTO	8	APR-12-2018 13:28	RTO	10
MAR-16-2015 10:25	RTO	24	MAY-11-2016 15:55	RTO	6	JAN-23-2017 09:08	RTO	7	JUN-04-2018 10:22	RTO	6
MAR-17-2015 23:34	RTO	17	JUN-01-2016 09:01	RTO	5	FEB-13-2017 18:30	RTO	7	JUN-29-2018 15:21	RTO	9
MAR-23-2015 23:44	RTO	15	JUL-06-2016 00:40	RTO	5	FEB-14-2017 00:11	RTO	6	JUN-30-2018 09:46	RTO	11
APR-06-2015 14:23	RTO	8	JUL-28-2016 13:28	RTO	15	FEB-15-2017 06:37	RTO	6	JUL-04-2018 10:56	RTO	7
APR-07-2015 17:11	RTO	31	AUG-31-2016 19:29	RTO	8	MAR-23-2017 06:48	RTO	24	JUL-10-2018 15:45	RTO	13
APR-15-2015 08:14	RTO	8	SEP-09-2016 19:11	RTO	6	APR-08-2017 11:53	RTO	10	JUL-23-2018 09:02	RTO	8
APR-25-2015 03:21	RTO	9	SEP-11-2016 19:30	RTO	9	MAY-08-2017 04:18	RTO	10	JUL-23-2018 15:43	RTO	6
JUL-30-2015 14:04	RTO	10	OCT-12-2016 08:21	RTO	5	JUN-08-2017 03:39	RTO	10	JUL-24-2018 16:17	RTO	7
AUG-05-2015 19:47	RTO	7	OCT-12-2016 14:40	RTO	7	JUN-20-2017 05:38	RTO	9	AUG-12-2018 11:06	RTO	11
AUG-19-2015 16:47	RTO	9	NOV-04-2016 17:13	RTO	11	SEP-04-2017 20:18	MAD	15	SEP-13-2018 09:47	RTO	7
SEP-05-2015 01:16	RTO	7	DEC-03-2016 00:11	RTO	7	SEP-07-2017 09:16	RTO	9	SEP-14-2018 13:24	RTO	7
SEP-10-2015 10:12	RTO	8	DEC-31-2016 05:10	RTO	12	SEP-21-2017 14:15	RTO	16	SEP-26-2018 19:08	RTO	8
SEP-29-2015 00:58	Mid-Atlantic	11							SEP-30-2018 11:29	RTO	11
NOV-12-2015 16:42	RTO	8							OCT-30-2018 10:40	RTO	11
NOV-21-2015 17:17	RTO	8									
DEC-04-2015 22:41	RTO	7									
DEC-24-2015 17:42	RTO	8									

Figure 10-13 Synchronized reserve events duration distribution curve: 2013 through 2018



Nonsynchronized Reserve Market

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

The market mechanism for nonsynchronized reserve does not include any direct participation by market participants. PJM defines the demand curve for nonsynchronized reserve and PJM defines the supply curve based on nonemergency generation resources that are available to provide energy and can start in 10 minutes or less and on the associated resource opportunity costs calculated by PJM. Generation owners do not submit supply offers. Since nonsynchronized reserve is a lower quality product, its clearing price is less than or equal to the synchronized reserve market clearing price. In most hours, the nonsynchronized reserve clearing price is zero.

Market Structure

Demand

Prior to July 12, 2017, PJM specified that 2,175 MW of primary reserve must be available in the Mid-Atlantic Dominion Reserve Subzone, of which 1,450 MW must be synchronized reserve (Figure 10-2), and that 2,175 MW of primary reserve must be available in the RTO Reserve Zone of which 1,450 MW must be synchronized reserve (Figure 10-3). As of July 12, 2017, the largest contingency is calculated dynamically in every synchronized and nonsynchronized reserve market solution and the primary requirement is set equal to 150 percent of the largest expected contingency within the upcoming hour. The balance of primary reserve can be made up by the most economic combination of synchronized and nonsynchronized reserve. PJM may increase the primary reserve requirement to cover times when a single contingency could cause an outage of several generating units or in times of high load conditions causing operational uncertainty.[51]

The average hourly demand in the RTO Zone for primary reserve in 2018 was 2,267.8 MW. The average five minute interval demand in the MAD Subzone for primary reserve in 2018 was 2,247.3 MW.

Supply

Figure 10-2 shows that most of the primary reserve requirement (orange line) in excess of the synchronized reserve requirement (yellow line) is satisfied by nonsynchronized reserve (light blue area).

There are no offers for nonsynchronized reserve. The hour ahead market solution considers the MW supply of nonsynchronized reserve to be all generation resources currently not synchronized to the grid but available and capable of providing energy within 10 minutes. Generators that have set themselves as unavailable or have set their output to be emergency only will not be considered. The market solution considers the offered MW to be the lesser of the economic maximum or the ramp rate times 10 minutes minus the startup and notification time. The offer price of nonsynchronized is the unit's opportunity cost of providing reserves.

51 See PJM "Manual 11: Energy and Ancillary Services Market Operations," § 4.2.2 Synchronized Reserve Requirement Determination, Rev. 101 (Jan. 9, 2019).

The market solution optimizes synchronized reserve, nonsynchronized reserve, and energy to satisfy the primary reserve requirement at the lowest cost. Nonsynchronized reserve resources are scheduled economically based on LOC until the Primary Reserve requirement is filled. The nonsynchronized reserve market clearing price is determined at the end of the hour based on the LOC of the marginal unit. When a unit clears the nonsynchronized reserve market and is scheduled, it is committed to remain offline for the hour and available to provide 10 minute reserves.

Resources that generally qualify as nonsynchronized reserve include run of river hydro, pumped hydro, combustion turbines and combined cycles that can start in 10 minutes or less, and diesels.[52] In 2018, an average of 1,968.8 MW of nonsynchronized reserve was scheduled hourly out of 3,683.2 eligible MW as part of the primary reserve requirement in the RTO Zone.

In 2018, CTs provided 78.0 percent of scheduled nonsynchronized reserve and hydro resources provided 21.5 percent. Less than one percent of cleared nonsynchronized reserve was provided by diesels.

Market Concentration

The supply of nonsynchronized reserves in the Mid-Atlantic Dominion Subzone and the RTO Zone was highly concentrated in 2018.

Table 10-23 Nonsynchronized reserve market HHIs: 2017 through 2018

Year	Month	MAD HHI	RTO HHI
2017	Jan	5538	5525
2017	Feb	5404	5402
2017	Mar	5679	5653
2017	Apr	4858	4847
2017	May	4213	4209
2017	Jun	3922	3922
2017	Jul	4106	4105
2017	Aug	4084	4084
2017	Sep	3806	3802
2017	Oct	3391	3391
2017	Nov	3125	3123
2017	Dec	2841	2841
2017		4247	4242
2018	Jan	3658	3651
2018	Feb	4063	4063
2018	Mar	4188	4188
2018	Apr	5248	5227
2018	May	3746	3706
2018	Jun	3815	3815
2018	Jul	4499	4499
2018	Aug	6310	6310
2018	Sep	4841	4804
2018	Oct	4151	4032
2018	Nov	4370	4340
2018	Dec	4675	4675
2018		4464	4443

Table 10-24 Nonsynchronized reserve market pivotal supplier test: 2017 through 2018

Year	Month	Non Synchronized Reserve Three Pivotal Supplier Hours
2017	Jan	32.2%
2017	Feb	31.1%
2017	Mar	38.1%
2017	Apr	38.1%
2017	May	52.3%
2017	Jun	60.4%
2017	Jul	55.9%
2017	Aug	57.1%
2017	Sep	70.8%
2017	Oct	82.1%
2017	Nov	57.1%
2017	Dec	92.5%
2017	Average	55.6%
2018	Jan	87.2%
2018	Feb	88.0%
2018	Mar	93.5%
2018	Apr	16.0%
2018	May	6.9%
2018	Jun	58.0%
2018	Jul	76.8%
2018	Aug	55.9%
2018	Sep	16.7%
2018	Oct	12.1%
2018	Nov	5.2%
2018	Dec	21.5%
2018	Average	44.8%

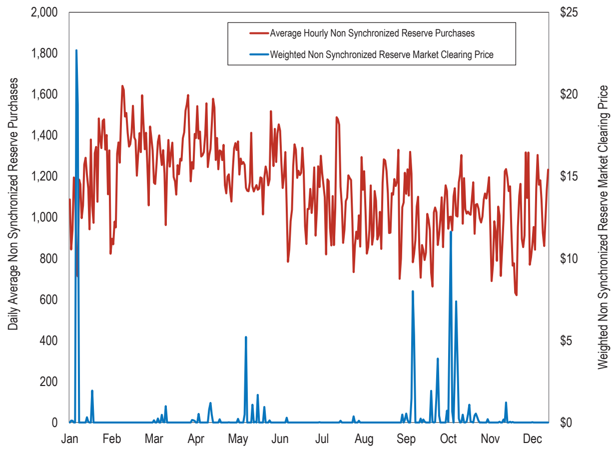
52 See PJM "Manual 11: Energy & Ancillary Services Market Operations," § 4b.2 Non-Synchronized Reserve Market Business Rules, Rev. 101 (Jan. 9, 2019).

Price

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

Figure 10-14 shows the daily average nonsynchronized reserve market clearing price and average scheduled MW for the RTO Zone. In 2018, the average nonsynchronized market clearing price was $0.29 per MW. The hourly average nonsynchronized reserve scheduled was 1,113.3 MW. For all of 2018, the market cleared at a price greater than $0 in 220 hours. The maximum hourly clearing price was $404.60 per MW on January 7, 2018.

Figure 10-14 Daily average RTO Zone nonsynchronized reserve market clearing price and MW purchased: 2018



Price and Cost

As a result of changing grid conditions, load forecasts, and unexpected generator performance, prices sometimes do not cover the full LOC of each resource. All resources cleared in the market are guaranteed to be made whole and are paid uplift credits if the NSRMCP does not fully compensate them. When real-time LMP rises above the generator's cost at economic minimum, then an LOC is paid.[53]

The full cost of nonsynchronized reserve including payments for the clearing price and uplift costs is calculated and compared to the price (Table 10-25). The closer the price to cost ratio comes to one, the more the market price reflects the full cost of nonsynchronized reserve.

In 2018, the price to cost ratio for the RTO Zone was 17.8 percent.

Resources that are not synchronized to the grid are generally off because it is not economic for them to produce energy. A resource scheduled for nonsynchronized reserve is obligated to remain unsynchronized even if its LMP changes and it becomes economic to start. In that case, the unit has a positive LOC.

Both nonsynchronized reserve markets cleared at a price above $0 in less than one percent of hours.

53 See PJM "Manual 11: Energy & Ancillary Services Market Operations," § 2.16 Minimum Capacity Emergency in Day-ahead Market, Rev. 101 (Jan. 9, 2019).

Table 10-25 RTO zone nonsynchronized reserve MW, charges, price, and cost: 2017 through 2018

Market	Year	Month	Total Nonsynchronized Reserve MW	Total Nonsynchronized Reserve Charges	Weighted Nonsynchronized Reserve Market Price	Nonsynchronized Reserve Cost	Price/Cost Ratio
RTO Zone	2017	Jan	585,294	$384,707	$0.15	$0.66	23.0%
RTO Zone	2017	Feb	599,301	$171,893	$0.00	$0.29	1.2%
RTO Zone	2017	Mar	548,021	$382,743	$0.14	$0.70	20.2%
RTO Zone	2017	Apr	653,581	$357,047	$0.13	$0.55	24.4%
RTO Zone	2017	May	796,190	$508,149	$0.16	$0.64	25.4%
RTO Zone	2017	Jun	841,672	$351,251	$0.03	$0.42	7.4%
RTO Zone	2017	Jul	745,694	$876,884	$0.13	$1.18	11.1%
RTO Zone	2017	Aug	874,602	$548,271	$0.01	$0.63	1.4%
RTO Zone	2017	Sep	867,103	$1,229,492	$0.73	$1.42	51.6%
RTO Zone	2017	Oct	929,944	$713,508	$0.02	$0.77	2.5%
RTO Zone	2017	Nov	850,863	$727,515	$0.05	$0.86	5.5%
RTO Zone	2017	Dec	936,590	$772,028	$0.00	$0.82	0.1%
RTO Zone	2017	Total	9,228,856	$7,023,487	$0.13	$0.76	17.1%
RTO Zone	2018	Jan	873,930	$4,616,906	$0.94	$5.28	17.7%
RTO Zone	2018	Feb	886,683	$249,232	$0.00	$0.28	0.0%
RTO Zone	2018	Mar	954,515	$1,693,691	$0.05	$1.77	3.0%
RTO Zone	2018	Apr	968,046	$1,385,351	$0.12	$1.52	7.9%
RTO Zone	2018	May	898,840	$1,894,687	$0.31	$2.66	11.8%
RTO Zone	2018	Jun	870,244	$1,026,193	$0.01	$1.22	1.2%
RTO Zone	2018	Jul	823,952	$639,914	$0.00	$0.74	0.7%
RTO Zone	2018	Aug	769,348	$858,148	$0.01	$1.05	1.4%
RTO Zone	2018	Sep	727,163	$986,756	$0.55	$1.52	36.1%
RTO Zone	2018	Oct	757,591	$1,590,789	$1.37	$2.60	52.8%
RTO Zone	2018	Nov	728,020	$566,419	$0.14	$0.74	19.5%
RTO Zone	2018	Dec	733,417	$348,069	$0.00	$0.44	0.8%
RTO Zone	2018	Total	9,991,749	$15,856,155	$0.29	$1.65	17.8%

Secondary Reserve

There is no NERC standard for secondary reserve. PJM defines secondary reserve as reserves (online or offline available for dispatch) that can be converted to energy in 30 minutes. PJM defines a secondary reserve requirement but does not have a goal to maintain this reserve requirement in real time.

PJM maintains a day-ahead, offer based market for 30 minute day-ahead secondary reserve. The Day-Ahead Scheduling Reserve Market (DASR) has no performance obligations except that a unit which clears the DASR market is required to be available for dispatch in real time.[54]

Market Structure

Supply

DASR is offered by both generation and demand resources. DASR offers consist of price only. Available DASR MW are calculated by the market clearing engine. DASR MW are the lesser of the energy ramp rate per minute for online units times 30 minutes, or the economic maximum MW minus the day-ahead dispatch point. For offline resources capable of being online in 30 minutes, the DASR quantity is the economic maximum. In 2018 the average available hourly DASR was 39,599.8 MW, an 8.3 percent increase from 2017. The DASR hourly MW purchased averaged 5,689.9 MW.

PJM excludes resources that cannot reliably provide reserves in real time from participating in the DASR Market. Such resources include nuclear, run of river hydro, self scheduled pumped hydro, wind, solar, and energy storage resources.[55] The intent of this proposal is to limit cleared DASR resources to those resources actually capable of providing reserves in the real-time market. Owners of excluded resources may request an exemption from their default noneligibility.

Of the 5,689.9 MW average hourly DASR cleared in 2018, 75.3 percent was from CTs, 7.3 percent was from steam, 12.3 percent was from hydro, and 4.6 percent was CCs. Load response resources which are registered in PJM's Economic Load Response and are dispatchable by PJM are eligible to provide DASR. In 2018, four demand resources offered into the DASR Market.

Demand

Secondary reserve (30 minute reserve) requirements are determined by PJM for each reliability region. In the ReliabilityFirst (RFC) region, secondary reserve requirements are calculated based on historical under forecasted load rates and generator forced outage

54 See PJM "Manual 11: Energy & Ancillary Services Market Operations," § 10.5 Aggregation for Economic and Emergency Demand Resources, Rev. 101 (Jan. 9, 2019).

55 See PJM "Manual 11: Energy & Ancillary Services Market Operations," § 11.2.2 Day-Ahead Scheduling Reserve Market Eligibility, Rev. 101 (Jan. 9, 2019).

rates.[56] The RFC and Dominion secondary reserve requirements are added together to form a single RTO DASR requirement defined as the sum of a percent of the load forecast error and forced outage rate times the daily peak load forecast. Effective January 1, 2019, the day-ahead scheduling reserve requirement will be 5.29 percent of the peak load forecast. This is based on a 2.18 percent load forecast error component and a 3.11 percent forced outage rate component. The DASR requirement is applicable for all hours of the operating day.

Effective March 1, 2015, the DASR requirement can be increased by PJM dispatch under conditions of "hot weather or cold weather alert or max emergency generation alert or other escalating emergency."[57] The amount of additional DASR MW that may be required is the Adjusted Fixed Demand (AFD) determined by a Seasonal Conditional Demand (SCD) factor.[58] The SCD factor is calculated separately for the winter (November through March) and summer (April through October) seasons. The SCD factor is calculated every year based on the top 10 peak load days from the prior year. For November 2018 through October 2019, the SCD values are 3.75 percent for winter and 2.45 percent for summer. PJM Dispatch may also schedule additional Day-Ahead Scheduling Reserves as deemed necessary for conservative operations.59 PJM has defined the reasons for conservative operations to include, potential fuel delivery issues, forest/brush fires, extreme weather events, environmental alerts, solar disturbances, unknown grid operating state, physical or cyber attacks.60 The result is substantial discretion for PJM to increase the demand for DASR under a variety of circumstances. PJM invoked adjusted fixed demand on 50 days during 2018. The 60 hours with highest DASR market clearing price were during days when adjusted fixed demand was invoked.

The MMU recommends that PJM modify the DASR Market to ensure that all resources cleared incur a real-time performance obligation.

56 See PJM "Manual 13: Emergency Operations," § 2.2 Reserve Requirements, Rev. 68 (Jan. 1, 2019)

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

58 See PJM "Manual 11: Energy & Ancillary Services Market Operations," § 11.2.1 Day-Ahead Scheduling Reserve Market Requirement. Rev. 101 (Jan. 9, 2019).

59 See PJM "Manual 11: Energy & Ancillary Services Market Operations," § 11.2.1 Day-Ahead Scheduling Reserve Market Reserve Requirement, Rev. 101 (Jan. 9, 2019).

60 See PJM "Manual 13: Emergency Operations," § 3.2 Conservative Operations, Rev. 68, (Jan. 1, 2019).

Market Concentration

DASR market three pivotal supplier test results are provided in Table 10-26.

Table 10-26 DASR market three pivotal supplier test results and number of hours with DASRMCP above $0: 2017 through 2018

Year	Month	Number of Hours When DASRMCP > $0	Percent of Hours Pivotal
2017	Jan	93	16.1%
2017	Feb	49	2.0%
2017	Mar	359	2.5%
2017	Apr	402	9.5%
2017	May	250	44.0%
2017	Jun	242	37.8%
2017	Jul	341	36.8%
2017	Aug	165	8.3%
2017	Sep	179	12.8%
2017	Oct	154	0.7%
2017	Nov	92	3.2%
2017	Dec	72	17.1%
2017	Average	200	15.9%
2018	Jan	197	7.6%
2018	Feb	14	40.9%
2018	Mar	66	0.0%
2018	Apr	189	0.5%
2018	May	339	5.6%
2018	Jun	101	11.8%
2018	Jul	190	11.5%
2018	Aug	161	16.8%
2018	Sep	146	22.6%
2018	Oct	117	0.0%
2018	Nov	20	0.0%
2018	Dec	10	0.0%
2018	Average	151	9.8%

Market Conduct

PJM rules allow any unit with reserve capability that can be converted into energy within 30 minutes to offer into the DASR Market.[61] Units that do not offer have their offers set to $0.00 per MW during the day-ahead market clearing process.

Economic withholding remains an issue in the DASR Market. The marginal cost of providing DASR is zero. All offers greater than zero constitute economic withholding. In 2018, 38.8 percent of generation units offered DASR at a daily price above $0.00, compared to 39.2 percent in 2017. In 2018, 15.8 percent of daily offers were above $5.00 per MW.

The MMU recommends that offers in the DASR Market be based on opportunity cost only in order to eliminate market power.

61 See PJM "Manual 11: Energy & Ancillary Services Market Operations," § 11.2.2 Day-Ahead Scheduling Reserve Market Eligibility, Rev. 101 (Jan. 9, 2019).

Market Performance

In 2018, the DASR Market cleared at a price above $0 in 17.8 percent of hours. The weighted average DASR price for all hours when the DASRMCP was above $0.00 was $3.49. In 2017, the weighted average DASR price for all hours when the DASRMCP was above $0.00 was $2.99. In 2018 the average cleared MW in all hours was 5,690.1 MW. The average cleared MW in all hours when the DASRMCP was above $0.00 was 6,976.2 MW. The highest DASR price was $66.04 on July 2, 2018.

The introduction of Adjusted Fixed Demand (AFD) on March 1, 2015, created a bifurcated market (Table 10-28). In 2015, PJM added AFD to the normal 5.93 percent of forecast load in 367 hours. In 2016, PJM added AFD to the normal 5.7 percent of forecast load in 522 hours. In 2017, PJM added AFD to the normal 5.52 percent of forecast load in 336 hours. In 2018 PJM added AFD to the normal 5.28 percent in 598 hours. The difference in market clearing price, MW cleared, obligation incurred, and charges to PJM load are substantial (Table 10-27).

Table 10-27 Impact of Adjusted Fixed Demand on DASR prices and demand: 2018

Metric	Year	Number Hours	Weighted Day-Ahead Scheduling Reserve Market Clearing Price (DASRMCP)	Average Hourly Total DASR MW
All Hours	Jan-Dec 2018	8,760	$0.39	5,571.2
All Hours when DASRMCP > $0	Jan-Dec 2018	1,553	$2.22	7,086.9
All Hours when AFD is used	Jan-Dec 2018	598	$4.88	9,977.9

While the new rules allow PJM dispatch substantial discretion to add to DASR demand for a variety of reasons, the rationale for each specific increase is not always clear. The MMU recommends that PJM Market Operations attach a reason code to every hour in which PJM dispatch adds additional DASR MW above the default DASR hourly requirement. The addition of such a code would make the reason explicit, increase transparency and facilitate analysis of the use of PJM's ability to add DASR MW.

Table 10-28 DASR Market, regular hours vs. adjusted fixed demand hours: 2017 through 2018

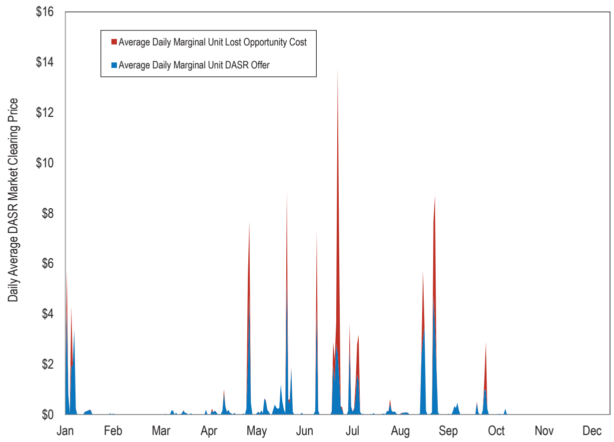
		Number of Hours DASRMCP>$0		Weighted DASRMCP		Average PJM Load MW		Hourly Average Cleared DASR MW		Average Hourly DASR Credits	
Year	Month	Normal Hour	AFD Hour	Normal Hour	AFD Hour	Normal Hour	AFD Hour	Normal Hour	AFD Hour	Normal Hour	AFD Hour
2017	Jan	93	0	$0.02		106,095		4,386		$91	
2017	Feb	49	0	$0.02		96,628		4,444		$92	
2017	Mar	359	0	$0.08		91,182		4,092		$329	
2017	Apr	402	0	$0.04		80,834		3,828		$159	
2017	May	250	48	$0.07	$18.13	85,581	98,184	4,004	10,727	$280	$194,491
2017	Jun	242	73	$0.18	$6.63	108,482	116,172	5,099	11,713	$907	$77,542
2017	Jul	341	115	$0.29	$6.41	114,832	117,568	5,288	10,669	$1,551	$68,397
2017	Aug	165	12	$0.42	$1.23	114,916	125,601	5,515	10,585	$2,318	$12,980
2017	Sep	179	22	$1.17	$40.30	105,850	104,097	5,111	11,652	$5,960	$466,893
2017	Oct	154	0	$0.33		89,402		4,404		$1,446	
2017	Nov	92	0	$0.20		91,098		4,950		$972	
2017	Dec	72	0	$0.27		110,878		5,675		$1,542	
2017		2,398	270	$0.26	$14.54	100,489	112,324	4,641	11,317	$1,298	$164,060
2018	Jan	197	120	$0.94	$3.56	97,785	119,404	5,220	9,164	$5,479	$32,627
2018	Feb	14	0	$0.00	NA	89,397	NA	5,066	NA	$16	NA
2018	Mar	66	0	$0.03	NA	87,295	NA	4,906	NA	$147	NA
2018	Apr	190	0	$0.10	NA	79,086	NA	4,508	NA	$444	NA
2018	May	339	72	$1.96	$8.99	82,800	91,483	4,758	10,886	$10,491	$97,845
2018	Jun	101	94	$0.75	$3.70	89,867	108,143	5,366	8,839	$4,369	$32,747
2018	Jul	190	168	$2.00	$5.97	97,978	109,671	5,899	9,949	$13,650	$59,428
2018	Aug	161	72	$0.71	$4.47	100,580	116,844	6,050	9,438	$4,540	$42,177
2018	Sep	146	72	$1.69	$7.70	87,995	115,611	5,117	12,483	$9,859	$96,066
2018	Oct	117	0	$0.20	NA	81,077	NA	4,665	NA	$948	NA
2018	Nov	20	0	$0.00	NA	85,755	NA	4,774	NA	$4	NA
2018	Dec	12	0	$0.00	NA	89,847	NA	5,121	NA	$2	NA
2018		1553	598	$0.39	$4.88	89,122	110,193	5,121	10,126	$4,162	$60,148

The implementation of AFD in 270 hours of 2017 and 598 hours of 2018 significantly increased the cost of DASR as a result of increases in DASR MW cleared and corresponding increases in the DASR clearing prices (Table 10-28).

Table 10-29 DASR Market all hours of DASR market clearing price greater than $0: 2017 through 2018

Year	Month	Number of Hours DASRMCP > $0	Weighted DASR Market Clearing Price	Average Hourly RT Load MW	Total PJM Cleared DASR MW	Total PJM Cleared Additional DASR MW	Total Charges
2017	Jan	93	$0.02	106,095	407,922	0	$8,426
2017	Feb	49	$0.02	96,628	217,737	0	$4,487
2017	Mar	359	$0.08	91,182	1,468,921	0	$117,995
2017	Apr	402	$0.04	80,834	1,539,010	0	$63,852
2017	May	250	$6.76	87,849	1,303,480	246,420	$8,809,449
2017	Jun	242	$3.20	110,611	1,677,956	383,822	$5,365,628
2017	Jul	341	$3.39	115,755	2,422,053	516,238	$8,216,211
2017	Aug	165	$0.53	115,693	970,853	49,896	$510,353
2017	Sep	179	$10.59	105,635	1,058,754	136,480	$11,207,356
2017	Oct	154	$0.33	89,402	678,175		$222,717
2017	Nov	92	$0.20	91,098	455,371		$89,460
2017	Dec	72	$0.27	110,878	408,569		$111,029
2017	Average	200	$2.12	100,138	1,050,733	148,095	$2,893,914
2017	Total	2,398			12,608,800	1,332,856	$34,726,963
2018	Jan	197	$2.66	101,276	3,869,914	481,887	$2,327,273
2018	Feb	14	$0.13	89,397	3,404,236	0	$10,436
2018	Mar	66	$0.32	87,295	3,650,839	0	$109,491
2018	Apr	190	$0.37	79,086	3,247,134	0	$319,905
2018	May	339	$3.73	83,640	3,586,629	395,742	$3,734,941
2018	Jun	101	$4.08	92,253	3,953,938	235,382	$2,315,966
2018	Jul	190	$6.09	100,619	4,506,459	562,931	$5,980,639
2018	Aug	161	$2.86	102,154	4,543,607	201,820	$2,228,076
2018	Sep	146	$5.55	90,756	3,779,739	434,532	$3,270,385
2018	Oct	117	$1.25	95,642	3,470,604	0	$705,607
2018	Nov	20	$0.03	100,565	3,447,112	0	$2,753
2018	Dec	10	$0.03	105,913	3,810,223	0	$1,310
2018	Average	129	$2.26	94,050	3,772,536	192,691	$1,750,565
2018	Total	1,551			45,270,434	2,312,294	$21,006,782

Figure 10-15 Daily average components of DASR clearing price ($/MW), marginal unit offer and LOC: 2018



When the DASR requirement is increased by PJM dispatch, the reserve requirement frequently cannot be met without redispatching online resources which significantly affects the price by creating an LOC (Figure 10-15). DASR prices had several severe peaks in January. PJM dispatch invoked 120 hours of Seasonal Conditional Demand, resulting in relatively high prices, during a period of cold weather from December 28, 2017, through January 7, 2018. The May 29, 2018 high price occurred during a hot weather alert and on the same day as the Twin Branch load shed event in AEP. The highest prices were $50.00 on January 8, 2018, and May 29, 2018.

Regulation Market

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

Market Design

PJM's regulation market design is a result of Order No. 755.[62] The objective of PJM's regulation market design is to minimize the cost to provide regulation using two resource types in a single market.

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

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

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

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

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

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

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

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

Regulation performance scores (0.0 to 1.0) measure the response of a regulating resource to its assigned regulation signal (RegA or RegD) every 10 seconds by measuring: delay, the time delay of the regulation response to a change in the regulation signal; correlation, the correlation between the regulating resource output and the regulation signal; and precision, the difference between the regulation response and the regulation requested.[63] Performance scores are reported on an hourly basis for each resource.

Figure 10-16 and Figure 10-17 show the average performance score by resource type and the signal followed in 2018. In these figures, the MW used are actual MW and the performance score is the hourly performance score of the regulation resource.[64] Each category (color bar) is based on the percentage of the full performance score distribution for each resource (or signal) type. As Figure 10-17 shows, 46.2 percent of RegD resources had average performance scores within the 0.91-1.00 range, and 18.2 percent of RegA resources had average performance scores within that range, in 2018. These scores are lower than the scores for both product types in 2017, where 60.1 percent of RegD resources had average performance scores within the 0.91-1.00 range, and 24.0 percent of RegA resources had average performance scores within that range.

Figure 10-16 Hourly average performance score by unit type: 2018

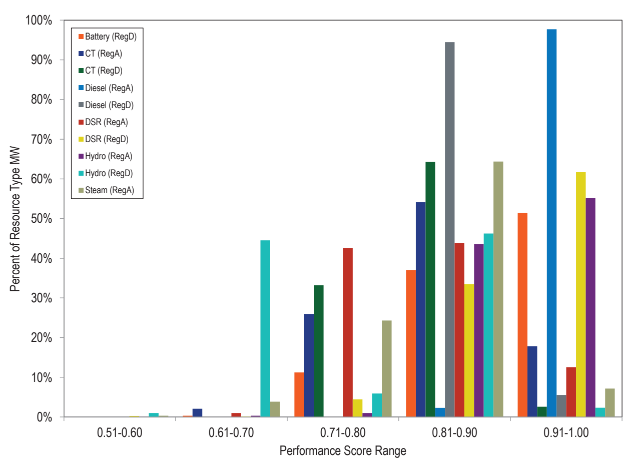
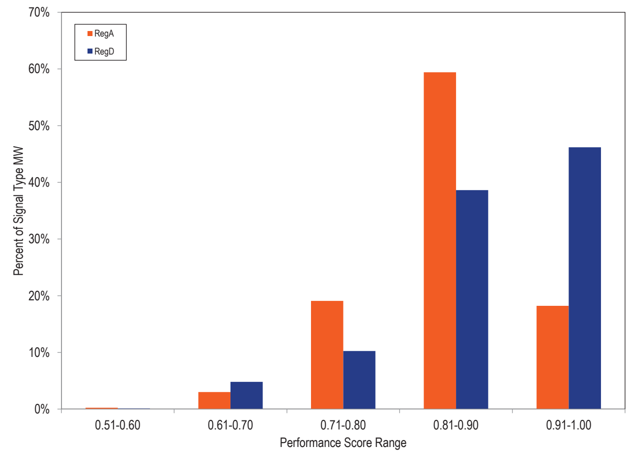


Figure 10-17 Hourly average performance score by regulation signal type: 2018



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

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

63 PJM "Manual 12: Balancing Operations," § 4.5.6 Performance Score Calculation, Rev. 39 (Feb. 21, 2019).

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

Market solution software relevant to regulation consists of the Ancillary Services Optimizer (ASO) solving hourly; the intermediate term security constrained economic dispatch market solution (IT-SCED) solving every 15 minutes; and the real-time security constrained economic dispatch market solution (RT-SCED) solving every five minutes. The market clearing price is determined by pricing software (LPC) that looks at the units cleared in the RT-SCED 15 minutes ahead of the pricing interval. The marginal price as identified by the LPC for each of these intervals is then averaged over the hour for an hourly regulation market clearing price.

Market Design Issues

PJM's current regulation market design is severely flawed and does not follow the appropriate basic design logic. The market results do not represent the least cost solution for the defined level of regulation service.

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

This flaw in the market design has caused operational issues, has caused over investment in RegD resources, and has caused significant price spikes in PJM's Regulation Market in 2018.

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

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

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

To address the identified market flaws, the MMU and PJM developed a joint proposal which was approved by the PJM Members Committee on July 27, 2017 and filed with the FERC on October 17, 2017. The PJM/MMU joint proposal addresses issues with the inconsistent application of the marginal benefit factor throughout the optimization and settlement process in the PJM Regulation Market. On March 30, 2018, FERC rejected the proposal finding it inconsistent with Order No. 755.[65] Both PJM and the MMU have filed requests for rehearing.[66]

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

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

65 162 FERC ¶ 61,295 (2018).
66 See FERC Docket No. ER18-87-002.

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

The January 9, 2017, design changes replaced off peak and on peak hours with nonramp and ramp hours with definitions that vary by season. The regulation requirement for ramp hours was increased from 700 MW to 800 MW (Table 10-30). These market changes still do not address the fundamental issues in the optimization or the lack of consistency in the application of the MBF.

Table 10-30 Seasonal regulation requirement definitions[67]

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

Performance Scores

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

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

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

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

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

a reduction in performance score and/or a forfeiture of revenues when resource owners elect to deassign assigned regulation resources within the hour, to prevent gaming.

Regulation Signal

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

MBF Issues

The MBF function, as implemented in the PJM Regulation Market, is not equal to the MRTS between RegA and RegD. The MBF is not consistently applied throughout the market design, from optimization to settlement, and market clearing does not confirm that the resulting combinations of RegA and RegD are realistic and can meet the defined regulation demand. The calculation of total regulation cleared using the MBF is incorrect.[68]

The result has been that the PJM Regulation Market has over procured RegD relative to RegA in most hours, has provided a consistently inefficient market signal to participants regarding the value of RegD in every hour, and has overpaid for RegD. In 2015, this over procurement began to degrade the ability of PJM to control ACE in some hours while at the same time increasing the cost of regulation. When the price paid for RegD is above the level defined by an accurate MBF function, there is an artificial incentive for inefficient entry of RegD resources.

The PJM/MMU joint proposal, filed with FERC on October 17, 2017, addresses issues with the inconsistent application of the marginal benefit factor throughout the optimization and settlement process in the PJM Regulation Market.[69]

Marginal Benefit Factor Not Correctly Defined

The MBF used in the PJM Regulation Market did not accurately reflect the MRTS between RegA and RegD resources under the old market design and it does not accurately reflect the MRTS between RegA and RegD resources under the modified design. The MBF function is incorrectly defined and improperly implemented in the current PJM Regulation Market.

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

The MBF is not included in PJM's settlement process. This is a design flaw that results in incorrect payments for regulation. The issue results from two FERC orders. From October 1, 2012, through October 31, 2013, PJM implemented a FERC order that required the MBF to be fixed at 1.0 for settlement calculations only. On October 2, 2013, FERC directed PJM to eliminate the use of the MBF entirely from settlement calculations of the capability and performance credits and replace it with the RegD to RegA mileage ratio in the performance credit paid to RegD resources, effective retroactively to October 1, 2012.[70] That rule continues in effect. The result of the current FERC order is that the MBF is used in market clearing to determine the relative value of an additional MW of RegD, but the MBF is not used in the settlement for RegD.

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

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

69 18 CFR § 385.211 (2017)

70 145 FERC ¶ 61,011 (2013).

and resources do not receive the same clearing price per marginal effective MW.

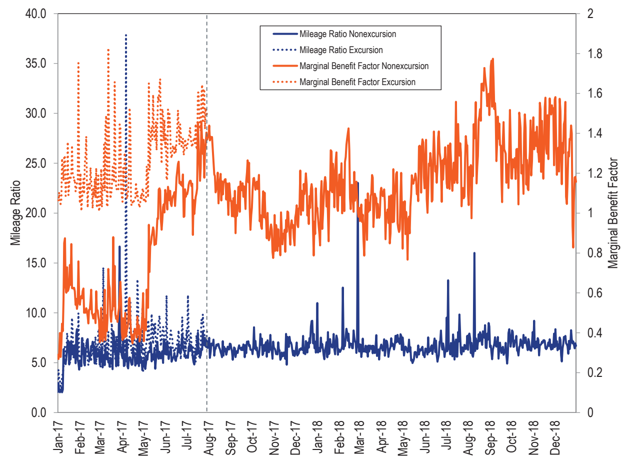
Figure 10-18 compares the daily average MBF and the mileage ratio for excursion and nonexcursion hours. Excursion hours (hours ending 7:00, 8:00, 18:00-21:00) were hours in which PJM had decided that more RegA was needed and PJM would not clear any RegD with an MBF less than 1.0.[71] Excursion hours were discontinued by PJM as of July 31, 2017. The shift in both the MBF values and the mileage ratio (Figure 10-18) resulted from the design changes implemented on January 9, 2017.

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

The weighted average mileage ratio during nonexcursion hours increased from 6.11 in 2017, to 6.82 in 2018 (an increase of 11.6 percent). The high mileage ratio values are the result of the mechanics of the mileage ratio calculation. The extreme mileage ratios result when the RegA signal is fixed at a single value ("pegged") to control ACE and the RegD signal is not. If RegA is held at a constant MW output, mileage is zero for RegA. The result of a fixed RegA signal is that RegA mileage is very small and therefore the mileage ratio is very large.

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

Figure 10-18 Daily average MBF and mileage ratio during excursion and nonexcursion hours: 2017 through 2018[72]



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

Table 10-31 shows RegD resource payments on a performance adjusted MW basis and RegA resource payments on a performance adjusted MW basis by month, from January 1, 2017, through December 31, 2018. In 2017, RegD resources earned 78.7 percent more per performance adjusted MW than RegA resources. In 2018, RegD resources earned 32.8 percent more per performance adjusted MW than RegA resources.

71 See "PJM Manual 11: Energy & Ancillary Services Market Operations,"§ 3.2.9 Regulation Market Operations, Rev. 101 (Jan. 9, 2019).

72 Excursion hours were discontinued as of 00:00 on July 31, 2017.

Table 10-31 Average monthly price paid per performance adjusted MW of RegD and RegA: 2017 through 2018

		Settlement Payments		
Year	Month	RegD ($/Performance Adjusted MW)	RegA ($/Performance Adjusted MW)	Percent Performance Adjusted RegD/RegA Overpayment
2017	Jan	$17.07	$13.62	25.4%
	Feb	$16.58	$10.64	55.8%
	Mar	$26.76	$15.06	77.7%
	Apr	$32.60	$15.58	109.2%
	May	$28.45	$17.89	59.0%
	Jun	$28.88	$13.23	118.2%
	Jul	$28.49	$15.00	89.9%
	Aug	$32.06	$13.24	142.1%
	Sep	$37.89	$21.33	77.6%
	Oct	$32.37	$16.11	100.9%
	Nov	$26.81	$15.62	71.7%
	Dec	$36.00	$25.13	43.3%
Average		$28.73	$16.08	78.7%
2018	Jan	$86.14	$78.36	9.9%
	Feb	$21.92	$12.22	79.3%
	Mar	$27.46	$21.76	26.2%
	Apr	$33.75	$26.41	27.8%
	May	$36.74	$29.36	25.1%
	Jun	$24.05	$18.06	33.2%
	Jul	$25.40	$18.79	35.2%
	Aug	$24.70	$15.92	55.2%
	Sep	$29.33	$20.09	46.0%
	Oct	$30.20	$19.45	55.3%
	Nov	$22.17	$14.39	54.0%
	Dec	$20.15	$12.44	61.9%
Average		$31.96	$24.07	32.8%

The current settlement process does not result in paying RegA and RegD resources the same price per effective MW. RegA resources are paid on the basis of dollars per effective MW of RegA. RegD resources are not paid in terms of dollars per effective MW of RegA because the MBF is not used in settlements. Instead of being paid based on the MBF (RMCCP + RMPCP)*MBF, RegD resources are currently paid based on the mileage ratio (RMCCP + (RMPCP*mileage ratio)). Because the RMCCP component makes up the majority of the overall clearing price, when the MBF is above one, RegD resources can be underpaid on a per effective MW basis by the current payment method, unless offset by a high mileage ratio. When the MBF is less than one, RegD resources are overpaid on a per effective MW basis. The average MBF was less than 1.0 in 2017 (0.96), resulting in an average overpayment of RegD resources. In 2018, the average MBF was equal to 1.2, however, RegD resources were still overpaid on average versus if they had been paid on a per effective MW basis.

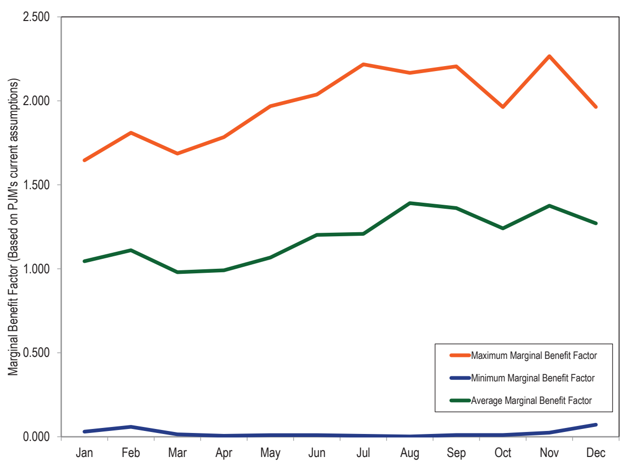
The effect of using the mileage ratio instead of the MBF to convert RegD MW into effective MW for purposes of settlement is illustrated in Table 10-32. Table 10-32 compares the monthly average payment to RegD per effective MW under the current settlement process to the monthly average payment RegD resources should have received using the MBF to convert RegD MW to effective MW. This also shows that using the MBF would result in RegA and RegD resources being paid exactly the same on a per effective MW basis. The MBF averaged less than one in 2017 (0.96), while the average daily mileage ratio was 6.32, resulting in RegD resources being paid $64.7 million more than they would have been if the MBF were correctly implemented. In 2018, the MBF averaged 1.2, while the average daily mileage ratio was 6.82, resulting in RegD resources being paid $20.4 million less than they would have been if the MBF were correctly implemented.

Table 10-32 Average monthly price paid per effective MW of RegD and RegA under mileage and MBF based settlement: 2017 through 2018

		RegD Settlement Payments				
Year	Month	Mileage Based RegD ($/Effective MW)	Marginal Rate of Technical Substitution Based RegD ($/Effective MW)	RegA ($/Effective MW)	Percent RegD Overpayment	Total RegD Overpayment ($)
2017	Jan	$80.44	$13.62	$13.62	490.7%	$6,674,174
	Feb	$293.97	$10.64	$10.64	2,662.3%	$23,955,220
	Mar	$80.90	$15.06	$15.06	437.2%	$5,885,287
	Apr	$79.84	$15.58	$15.58	412.4%	$5,761,398
	May	$34.79	$17.89	$17.89	94.4%	$1,985,119
	Jun	$24.18	$13.23	$13.23	82.7%	$1,481,005
	Jul	$22.16	$15.00	$15.00	47.7%	$1,021,794
	Aug	$26.53	$13.24	$13.24	100.4%	$1,874,341
	Sep	$35.67	$21.33	$21.33	67.2%	$1,719,466
	Oct	$33.29	$16.11	$16.11	106.7%	$2,119,188
	Nov	$27.43	$15.62	$15.62	75.6%	$1,367,771
	Dec	$30.24	$25.13	$25.13	20.3%	$693,153
Yearly		$62.44	$16.08	$16.08	288.3%	$64,657,186
2018	Jan	$70.22	$78.36	$78.36	(10.4%)	($1,127,265)
	Feb	$16.69	$12.22	$12.22	36.5%	$560,643
	Mar	$21.85	$21.76	$21.76	0.4%	$11,868
	Apr	$28.52	$28.08	$28.08	1.6%	$56,125
	May	$32.51	$31.22	$31.22	4.1%	$166,582
	Jun	$21.11	$15.48	$15.48	36.3%	$736,671
	Jul	$138.39	$17.84	$17.84	675.7%	$15,177,248
	Aug	$36.26	$13.14	$13.14	175.9%	$3,086,258
	Sep	$20.86	$20.42	$20.42	2.2%	$56,086
	Oct	$22.31	$18.49	$18.49	20.7%	$503,136
	Nov	$13.19	$12.64	$12.64	4.4%	$70,761
	Dec	$14.55	$12.46	$12.46	16.8%	$287,209
Yearly		$36.70	$23.64	$23.64	55.2%	$20,404,205

Figure 10-19 shows, for 2018, the maximum, minimum and average MBF, by month, for excursion and nonexcursion hours. The average MBF in 2018 was 1.2. The average MBF in 2017 was 0.96.

Figure 10-19 Maximum, minimum, and average PJM calculated MBF by month: 2018[73]



73 Excursion hours were discontinued as of 00:00 on July 31, 2017.

Table 10-33 shows performance adjusted and effective MW that were eligible and cleared during 2017 and 2018.

Table 10-33 Performance adjusted and effective RegD MW eligible and cleared: 2017 and 2018

Performance Adjusted RegD MW			
	2017	2018	Change
Actual Eligible	316.3	272.0	(14.0%)
Effective Eligible	316.3	286.9	(9.3%)
Actual Cleared	186.6	157.9	(15.4%)
Effective Cleared	309.2	273.4	(11.6%)

The MMU recommends that the Regulation Market be modified to incorporate a consistent and correct application of the MBF throughout the optimization, assignment and settlement process.[74]

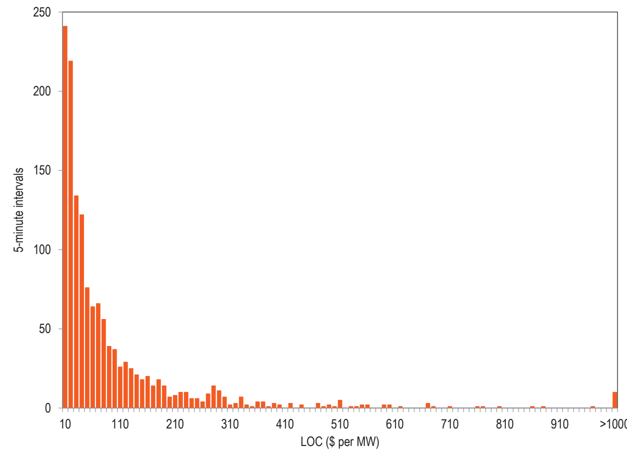
Price Spikes

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

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

In some cases the estimated LOC is very low or zero but the actual within hour LOC is a positive number. In instances where the MBF of the within hour marginal unit was very low (less than one), this discrepancy in the estimated and realized LOC will cause a large discrepancy between the expected offer price (as low as $0/MW) of that resource in the clearing of the market engine, and the realized offer price of the resource, after it is cleared, in the actual market result. This will cause a significant and unexpected price spike in the regulation market. In cases where the MBF of the marginal resource is very low, such as 0.001, the price spikes can be very significant for a small change between expected and actual LOC. Figure 10-20 shows the LOC in each five-minute interval in which a RegD unit was the marginal unit and the LOC was greater than zero in 2018.

Figure 10-20 LOC distribution in each five-minute interval with a RegD marginal unit and an LOC greater than zero, in 2018



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

While an incorrect estimate of a potential LOC can result in an extremely high price, the resulting regulation market prices are mathematically correct for the price of each effective MW. The prices in every interval reflect the marginal costs of regulation given the resources dispatched and accurately reflect the marginal offer of minimally effective resources which had unexpectedly high LOC components of their within hour offers. Bit,

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

due to the current market design's failure to make use of the MBF in settlement, RegD is not paid on a dollar per effective MW basis. This disconnect between the process of setting price and the process of paying resources is the primary source of the market failure in PJM's Regulation Market and the cause of the observed price spikes in the regulation market. In the example, the 0.001 MW from the RegD resource should be paid $1,000 times 0.001 MW or $1.00. But the current rules would pay the RegD resource $1,000 times 1.0 MW or $1,000. If the market clearing and the settlements rules were consistent, the incentive for this behavior would be eliminated. The current rules provide a strong incentive for this behavior.

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

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

Market Structure

Supply

Table 10-34 shows capability MW (performance adjusted), average daily offer MW (performance adjusted), average hourly eligible MW (performance adjusted and effective), and average hourly cleared MW (performance adjusted and effective) for all hours in 2018.[75] Total MW are adjusted by the historic 100-hour moving average performance score to get performance adjusted MW, and by the resource specific benefit factor to get effective MW. A resource can choose to follow either signal. For that reason, the sum of each signal type's capability can exceed the full regulation capability. Offered MW are calculated based on the daily offers from units that are offered as available for the day. Eligible MW are calculated from the hourly offers from units with daily offers and units that are offered as unavailable for the day, but still offer MW into some hours. Units with daily offers are permitted to offer above or below their daily offer from hour to hour. As a result of these hourly MW adjustments, the average hourly Eligible MW can be higher than the Offered MW.

In 2018, the average hourly eligible supply of regulation for nonramp hours was 1,125.5 performance adjusted MW (876.2 effective MW). This was a decrease of 10.6 performance adjusted MW (a decrease of 7.1 effective MW) from 2017, when the average hourly eligible supply of regulation was 1,136.1 performance adjusted MW (869.0 effective MW). In 2018, the average hourly eligible supply of regulation for ramp hours was 1,438.3 performance adjusted MW (1,204.1 effective MW). This was an increase of 11.1 performance adjusted MW (an increase of 20.7 effective MW) from 2017, when the average hourly eligible supply of regulation was 1,427.2 performance adjusted MW (1,183.4 effective MW).

The ratio of the average hourly eligible supply of regulation to average hourly regulation demand (performance adjusted cleared MW) for ramp hours was 1.92 in 2018. This is a decrease of 3.22 percent from 2017, when the ratio was 1.98. The ratio of the average hourly eligible supply of regulation to average hourly regulation demand (performance adjusted cleared MW) for nonramp hours was 2.33 in 2018. This is an increase of 0.10 percent from 2017, when the ratio was 2.33.

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

Table 10-34 PJM regulation capability, daily offer and hourly eligible: 2018[76 77]

			By Resource Type		By Signal Type	
		All Regulation	Generating Resources	Demand Resources	RegA Following Resources	RegD Following Resources
Capability MW	Daily	11,023.5	10,991.8	31.7	10,663.9	632.5
Offered MW	Daily	5,428.1	5,406.0	22.1	5,093.4	334.7
Actual Eligible MW	Ramp	1,438.3	1,417.3	21.0	1,147.9	290.4
	Nonramp	1,125.5	1,105.9	19.6	871.8	253.7
Effective Eligible MW	Ramp	1,204.1	1,174.5	29.6	874.0	330.1
	Nonramp	876.2	851.7	24.5	632.6	243.6
Actual Cleared MW	Ramp	749.7	736.4	13.3	575.4	174.3
	Nonramp	482.9	471.1	11.8	341.4	141.5
Effective Cleared MW	Ramp	799.8	771.7	28.1	488.8	311.1
	Nonramp	526.0	502.6	23.4	290.3	235.7

Table 10-35 provides the settled regulation MW by source unit type, the total settled regulation MW provided by all resources, and the percent of settled regulation provided by unit type. In Table 10-35 the MW have been adjusted by the performance score since this adjustment forms the basis of payment for units providing regulation. Total regulation performance adjusted capability MW increased 1.1 percent from 4,583,402.4 MW in 2017 to 4,633,167.2 MW in 2018. The average proportion of regulation provided by natural gas units had the largest increase (8.1 percent), providing 40.2 percent of regulation in 2017 and 48.3 percent of regulation in 2018. Battery units had the largest decrease in average proportion of regulation provided (8.8 percent), decreasing from 30.0 percent in 2017, to 21.2 percent in 2018. The total regulation credits in 2018 were $145,483,539 up 39.6 percent from $104,478,748 in 2017.

Table 10-35 PJM regulation by source: 2017 and 2018[78]

	2017				2018			
Source	Number of Units	Performance Adjusted Settled Regulation (MW)	Percent of Settled Regulation	Total Regulation Credits	Number of Units	Performance Adjusted Settled Regulation (MW)	Percent of Settled Regulation	Total Regulation Credits
Battery	22	1,376,847.1	30.0%	$38,907,116	23	981,768.0	21.2%	$32,612,688
Coal	42	392,183.0	8.6%	$9,971,617	37	410,773.8	8.9%	$18,544,611
Hydro	27	907,927.5	19.8%	$18,490,838	28	904,072.7	19.5%	$29,979,158
Natural Gas	156	1,842,498.1	40.2%	$35,266,796	168	2,237,299.1	48.3%	$61,286,347
DR	29	63,947	1.4%	$1,842,380	30	99,254	2.1%	$3,060,736
Total	276	4,583,402.4	100.0%	$104,478,748	286	4,633,167.2	100.0%	$145,483,539

Significant flaws in the regulation market design have led to an over procurement of RegD MW primarily in the form of storage capacity. The incorrect market signals have led to more storage projects entering PJM's interconnection queue, despite clear evidence that the market design is flawed and despite operational evidence that the RegD market is saturated (Table 10-36).

Table 10-36 Active battery storage projects in the PJM queue system by submitted year: 2012 to 2018

Year	Number of Storage Projects	Total Capacity (MW)
2012	1	4.5
2013	0	0.0
2014	2	30.0
2015	29	106.1
2016	3	41.2
2017	3	2.5
2018	33	1,011.4
Total	71	1,195.7

76 Average Daily Offer MW excludes units that have offers but are unavailable for the day.

77 Total offer capability is defined as the sum of the maximum daily offer volume for each offering unit during the period, without regard to the actual availability of the resource or to the day on which the maximum was offered.

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

The supply of regulation can be affected by regulating units retiring from service. If all units that are requesting retirement through the end of 2018 retire, the supply of regulation in PJM will be reduced by less than one percent.

Demand

The demand for regulation does not change with price. The regulation requirement is set by PJM to meet NERC control standards, based on reliability objectives, which means that a significant amount of judgment is exercised by PJM in determining the actual demand. Prior to October 1, 2012, the regulation requirement was 1.0 percent of the forecast peak load for on peak hours and 1.0 percent of the forecast valley load for off peak hours. Between October 1, 2012, and December 31, 2012, PJM changed the regulation requirement several times. It had been scheduled to be reduced from 1.0 percent of peak load forecast to 0.9 percent on October 1, 2012, but instead it was changed from 1.0 percent of peak load forecast to 0.78 percent of peak load forecast. It was further reduced to 0.74 percent of peak load forecast on November 22, 2012 and reduced again to 0.70 percent of peak load forecast on December 18, 2012. On December 14, 2013, it was reduced to 700 effective MW during peak hours and 525 effective MW during off peak hours. The regulation requirement remained 700 effective MW during peak hours and 525 effective MW during off peak hours until January 9, 2017. A change to the regulation requirement was approved by the RMISTF in 2016, with an implementation date of January 9, 2017. The regulation requirement was increased from 700 effective MW to 800 effective MW during ramp hours (Table 10-30).

Table 10-37 shows the average hourly required regulation by month and the ratio of supply to demand for both actual and effective MW, for ramp and nonramp hours. The average hourly required regulation by month is an average of the ramp and nonramp hours in the month.

The nonramp regulation requirement of 525.0 effective MW was provided by a combination of RegA and RegD resources equal to 483.0 hourly average performance adjusted actual MW in 2018. This is a decrease of 5.1 performance adjusted actual MW from 2017, when the average hourly total regulation cleared performance adjusted actual MW for nonramp hours were 488.1 performance adjusted actual MW. The ramp regulation requirement of 800.0 effective MW was provided by a combination of RegA and RegD resources equal to 749.3 hourly average performance adjusted actual MW in 2018. This is an increase of 29.1 performance adjusted actual MW from 2017, where the average hourly regulation cleared MW for ramp hours were 720.2 performance adjusted actual MW.

Table 10-37 Required regulation and ratio of supply to requirement: 2017 and 2018[79]

		Average Required Regulation (MW)		Average Required Regulation (Effective MW)		Ratio of Supply MW to MW Requirement		Ratio of Supply Effective MW to Effective MW Requirement	
Hours	Month	2017	2018	2017	2018	2017	2018	2017	2018
Ramp	Jan	690.8	756.8	766.8	800.0	2.10	1.88	1.48	1.49
	Feb	705.8	738.7	800.1	799.9	2.11	1.90	1.52	1.48
	Mar	714.7	742.9	800.1	800.0	1.96	1.86	1.41	1.43
	Apr	730.6	747.4	800.0	799.9	1.86	1.76	1.41	1.39
	May	723.6	747.2	800.0	800.1	1.88	1.76	1.44	1.42
	Jun	719.9	746.4	800.0	800.0	1.98	1.88	1.49	1.51
	Jul	727.6	756.2	799.9	800.0	2.00	1.91	1.52	1.54
	Aug	727.8	760.4	800.3	800.1	1.97	1.94	1.50	1.53
	Sep	728.3	754.0	799.9	797.3	1.90	1.98	1.46	1.57
	Oct	716.8	752.0	800.0	800.0	2.09	1.92	1.59	1.49
	Nov	713.6	747.3	800.1	800.1	1.99	2.13	1.50	1.63
	Dec	742.6	742.3	799.9	800.1	1.91	2.08	1.48	1.55
Nonramp	Jan	503.6	497.6	525.1	525.1	2.45	2.27	1.65	1.71
	Feb	508.3	482.0	525.0	525.2	2.47	2.37	1.75	1.70
	Mar	499.9	486.6	525.0	525.2	2.22	2.35	1.52	1.67
	Apr	519.0	488.1	525.0	525.0	2.20	2.03	1.60	1.47
	May	479.7	481.5	525.1	524.9	2.26	2.13	1.59	1.55
	Jun	471.9	482.7	525.1	524.9	2.31	2.36	1.63	1.68
	Jul	484.9	488.8	541.0	525.0	2.32	2.24	1.66	1.63
	Aug	481.8	483.5	535.2	525.1	2.41	2.32	1.71	1.65
	Sep	475.8	490.5	526.4	535.1	2.26	2.33	1.62	1.66
	Oct	470.5	477.2	525.2	525.1	2.45	2.30	1.74	1.60
	Nov	472.8	471.1	525.1	525.1	2.34	2.61	1.67	1.83
	Dec	489.5	466.5	525.1	525.1	2.37	2.74	1.71	1.89

Market Concentration

In 2018, the effective MW weighted average HHI of RegA resources was 2419 which is highly concentrated and the weighted average HHI of RegD resources was 1546 which is also highly concentrated.[80] The weighted average HHI of all resources was 1125, which is moderately concentrated. The HHI of RegA resources and the HHI of RegD resources are higher than the HHI for all resources because different owners have large market shares in the RegA and RegD markets.

Table 10-38 includes a monthly summary of three pivotal supplier (TPS) results. In 2018, 81.7 percent of hours had three or fewer pivotal suppliers. The MMU concludes that the PJM Regulation Market in 2018 was characterized by structural market power.

Table 10-38 Regulation market monthly three pivotal supplier results: 2017 through 2018

	Percent of Hours Pivotal		
Month	2016	2017	2018
Jan	93.9%	90.6%	88.7%
Feb	90.9%	93.1%	77.5%
Mar	87.8%	92.7%	83.9%
Apr	93.5%	92.9%	90.3%
May	94.0%	88.7%	87.8%
Jun	89.3%	89.2%	79.9%
Jul	92.2%	91.0%	79.4%
Aug	93.7%	88.0%	79.6%
Sep	94.0%	82.6%	78.6%
Oct	90.6%	68.1%	82.1%
Nov	96.2%	72.5%	78.2%
Dec	90.4%	79.3%	74.2%
Average	92.2%	85.7%	81.7%

79 The regulation requirement for January 2017 includes eight days of 700 effective MW and 23 days of 800 effective MW.

80 HHI results are based on market shares of effective MW, defined as regulation capability MW adjusted by performance score and resource specific benefit factor, consistent with the way the regulation market is cleared.

Market Conduct

Offers

Resources seeking to regulate must qualify to follow a regulation signal by passing a test for that signal with at least a 75 percent performance score. The regulating resource must be able to supply at least 0.1 MW of regulation and not allow the sum of its regulating ramp rate and energy ramp rate to exceed its overall ramp rate.[81] When offering into the regulation market, regulating resources must submit a cost-based offer and may submit a price-based offer (capped at $100/MW) by 2:15 pm the day before the operating day.[82]

Offers in the PJM Regulation Market consist of a capability component for the MW of regulation capability provided and a performance component for the miles (ΔMW of regulation movement) provided. The capability component for cost-based offers is not to exceed the increased fuel costs resulting from operating the regulating unit at a lower output level than its economically optimal output level, plus a $12.00/MW margin. The $12.00 margin embeds market power in the regulation offers and is not part of the cost of regulation. The performance component for cost-based offers is not to exceed the increased costs (increased short run marginal costs including increased fuel costs) resulting from moving the unit up and down to provide regulation. Batteries and flywheels have zero cost for lower efficiency from providing regulation instead of energy, as they are not net energy producers. There is an energy storage loss component for batteries and flywheels as a cost component of regulation performance offers to reflect the net energy consumed to provide regulation service.[83]

Up until one hour before the operating hour, the regulating resource must provide: status (available, unavailable, or self scheduled); capability (movement up and down in MW); regulation maximum and regulation minimum (the highest and lowest levels of energy output while regulating in MW); and the regulation signal type (RegA or RegD). Resources may offer regulation for both the RegA and RegD signals, but will be assigned to follow only one signal for a given operating hour. Resources have the option to submit a minimum level of regulation they are willing to provide.[84]

All LSEs are required to provide regulation in proportion to their load share. LSEs can purchase regulation in the regulation market, purchase regulation from other providers bilaterally, or self schedule regulation to satisfy their obligation (Table 10-40).[85] Figure 10-21 compares average hourly regulation and self scheduled regulation during ramp and nonramp hours on an effective MW basis. The average hourly regulation is the amount of regulation that actually cleared and is not the same as the regulation requirement because PJM clears the market within a two percent band around the requirement.[86] Self scheduled regulation comprised an average of 33.6 percent during ramp hours and 45.6 percent during nonramp hours in 2018.

Figure 10-21 Off peak, on peak, nonramp, and ramp regulation levels: 2017 through 2018[87]

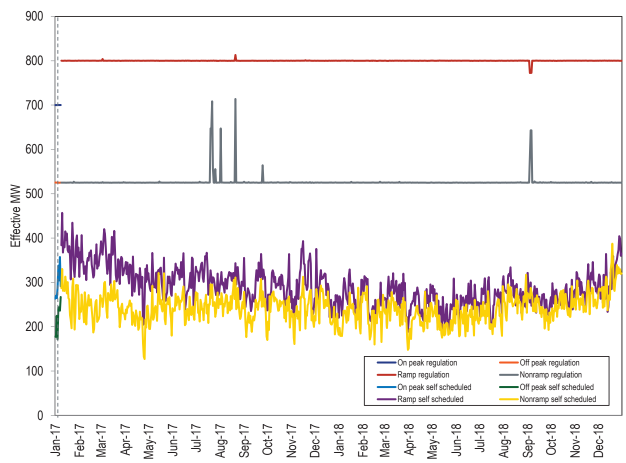


Table 10-39 shows the role of RegD resources in the regulation market. RegD resources are both a growing proportion of the market (10.9 percent of the total effective MW at the start of the performance based regulation market design in October 2012 and 40.5 percent of the total effective MW in December 2018) and a growing proportion of resources that self schedule (10.1 percent of all self scheduled MW in October 2012

81 See "PJM Manual 11: Energy & Ancillary Services Market Operations," § 3.2.1 Regulation Market Eligibility, Rev. 101 (Jan. 9, 2019).

82 Id. at 3.2.2, at p 62.

83 See "PJM Manual 15: Cost Development Guidelines," § 7.8 Regulation Cost, Rev. 29 (May 15, 2017).

84 See "PJM Manual 11: Energy & Ancillary Services Market Operations," § 3.2.1 Regulation Market Eligibility, Rev. 101 (Jan.9, 2019).

85 See "PJM Manual 28: Operating Agreement Accounting," § 4.1Regulation Accounting Overview, Rev. 81 (Oct. 25, 2018).

86 See "PJM Manual 11: Energy & Ancillary Services Market Operations," § 3.2.1 Regulation Market Eligibility, Rev. 101 (Jan 9, 2019).

87 The MW increases during the nonramp hours of 2017 and 2018 were a result of PJM operations treating those hours as ramp hours.

and 25.5 percent of all self scheduled MW in December 2018). The increase in the share of RegD in 2016 was a result of the use of the unit block method of calculating the MBF over the previous price block method (Table 10-39). The decrease in the RegD share of total effective MW for 2017 and 2018 were a result of a decrease in the amount of eligible MW of RegD (Table 10-33) in response to the changes to the regulation market on January 9, 2017.

Table 10-39 RegD self scheduled regulation by month: October 2012 through 2018

Year	Month	RegD Self Scheduled Effective MW	RegD Effective MW	Total Self Scheduled Effective MW	Total Effective MW	Percent of Total Self Scheduled	RegD Percent of Total Self Scheduled	RegD Percent of Total Effective MW
2012	Oct	66.3	71.8	264.7	658.1	40.2%	10.1%	10.9%
2012	Nov	74.4	88.3	196.5	716.5	27.4%	10.4%	12.3%
2012	Dec	82.5	88.8	188.8	701.1	26.9%	11.8%	12.7%
2013	Jan	35.7	82.5	133.6	720.0	18.6%	5.0%	11.5%
2013	Feb	84.8	90.2	212.2	724.3	29.3%	11.7%	12.5%
2013	Mar	80.1	119.3	279.8	680.7	41.1%	11.8%	17.5%
2013	Apr	82.3	106.9	266.0	594.1	44.8%	13.8%	18.0%
2013	May	74.0	109.0	268.2	616.2	43.5%	12.0%	17.7%
2013	Jun	79.6	122.7	334.9	730.6	45.8%	10.9%	16.8%
2013	Jul	77.6	120.4	303.6	822.9	36.9%	9.4%	14.6%
2013	Aug	83.6	127.6	366.0	756.8	48.4%	11.0%	16.9%
2013	Sep	112.2	152.1	381.6	669.9	57.0%	16.7%	22.7%
2013	Oct	120.2	163.7	349.6	613.3	57.0%	19.6%	26.7%
2013	Nov	133.9	175.7	396.5	663.3	59.8%	20.2%	26.5%
2013	Dec	136.5	180.7	313.6	663.5	47.3%	20.6%	27.2%
2013 Average		91.7	129.2	300.5	688.0	44.1%	13.6%	19.0%
2014	Jan	132.9	193.5	261.1	663.6	39.3%	20.0%	29.2%
2014	Feb	134.3	193.4	289.0	663.6	43.5%	20.2%	29.1%
2014	Mar	131.8	193.8	287.2	663.8	43.3%	19.9%	29.2%
2014	Apr	126.8	212.4	270.8	663.7	40.8%	19.1%	32.0%
2014	May	121.7	248.5	265.6	663.6	40.0%	18.3%	37.4%
2014	Jun	123.3	231.0	365.5	663.9	55.0%	18.6%	34.8%
2014	Jul	126.4	235.5	352.7	663.5	53.2%	19.0%	35.5%
2014	Aug	117.6	229.8	368.2	663.6	55.5%	17.7%	34.6%
2014	Sep	121.0	242.6	393.8	663.6	59.3%	18.2%	36.6%
2014	Oct	116.1	255.4	352.7	663.6	53.2%	17.5%	38.5%
2014	Nov	113.5	235.1	347.5	664.2	52.3%	17.1%	35.4%
2014	Dec	116.7	254.3	353.0	663.6	53.2%	17.6%	38.3%
2014 Average		123.5	227.1	325.6	663.7	49.1%	18.6%	34.2%
2015	Jan	116.4	250.1	304.8	663.7	45.9%	17.5%	37.7%
2015	Feb	111.3	245.8	242.6	663.5	36.6%	16.8%	37.0%
2015	Mar	113.8	255.2	229.9	663.8	34.6%	17.1%	38.5%
2015	Apr	110.1	248.2	283.7	663.7	42.7%	16.6%	37.4%
2015	May	121.8	265.1	266.7	663.6	40.2%	18.4%	39.9%
2015	Jun	158.9	283.1	321.2	663.7	48.4%	23.9%	42.6%
2015	Jul	161.4	278.3	314.0	663.8	47.3%	24.3%	41.9%
2015	Aug	159.5	276.0	300.7	663.6	45.3%	24.0%	41.6%
2015	Sep	155.4	289.2	286.0	663.5	43.1%	23.4%	43.6%
2015	Oct	147.1	299.0	292.8	663.4	44.1%	22.2%	45.1%
2015	Nov	164.9	302.1	298.1	664.2	44.9%	24.8%	45.5%
2015	Dec	144.6	317.2	260.7	663.9	39.3%	21.8%	47.8%
2015 Average		138.8	275.8	283.4	663.7	42.7%	20.9%	41.6%
2016	Jan	187.7	335.9	295.3	663.8	44.5%	28.3%	50.6%
2016	Feb	179.9	339.0	274.6	663.6	41.4%	27.1%	51.1%
2016	Mar	182.6	340.8	280.1	663.7	42.2%	27.5%	51.3%
2016	Apr	182.2	339.5	287.0	663.5	43.3%	27.5%	51.2%
2016	May	183.9	341.1	301.5	663.5	45.4%	27.7%	51.4%
2016	Jun	178.8	340.5	302.4	663.6	45.6%	26.9%	51.3%
2016	Jul	165.2	337.5	273.3	663.5	41.2%	24.9%	50.9%
2016	Aug	165.8	338.5	283.2	663.5	42.7%	25.0%	51.0%
2016	Sep	160.9	341.4	279.9	663.6	42.2%	24.2%	51.4%
2016	Oct	168.6	340.0	283.0	663.5	42.6%	25.4%	51.2%
2016	Nov	156.2	338.0	259.8	664.3	39.1%	23.5%	50.9%
2016	Dec	162.2	342.7	274.7	663.6	41.4%	24.4%	51.6%
2016 Average		172.8	339.6	282.9	663.7	42.6%	26.0%	51.2%

Table 10-39 RegD self scheduled regulation by month: October 2012 through 2018 (continued)

Year	Month	RegD Self Scheduled Effective MW	RegD Effective MW	Total Self Scheduled Effective MW	Total Effective MW	Percent of Total Self Scheduled	RegD Percent of Total Self Scheduled	RegD Percent of Total Effective MW
2017	Jan	187.1	334.9	318.0	673.9	47.2%	27.8%	49.7%
2017	Feb	192.7	337.8	296.6	674.2	44.0%	28.6%	50.1%
2017	Mar	172.2	315.3	297.5	638.5	46.6%	27.0%	49.4%
2017	Apr	159.9	306.4	255.0	639.6	39.9%	25.0%	47.9%
2017	May	167.6	297.0	265.7	639.7	41.5%	26.2%	46.4%
2017	Jun	178.6	315.6	284.3	696.9	40.8%	25.6%	45.3%
2017	Jul	171.9	310.3	290.0	703.1	41.3%	24.5%	44.1%
2017	Aug	176.7	314.0	286.3	700.9	40.8%	25.2%	44.8%
2017	Sep	156.9	297.8	259.0	640.4	40.4%	24.5%	46.5%
2017	Oct	158.6	295.3	263.7	639.7	41.2%	24.8%	46.2%
2017	Nov	158.6	298.1	261.7	640.4	40.9%	24.8%	46.5%
2017	Dec	147.7	290.8	260.6	674.0	38.7%	21.9%	43.1%
2017 Average		164.1	286.2	269.6	663.4	40.6%	8.2%	45.7%
2018	Jan	130.6	274.3	247.4	673.8	36.7%	19.4%	40.7%
2018	Feb	131.1	276.6	245.5	674.0	36.4%	19.5%	41.0%
2018	Mar	126.6	270.9	249.4	639.8	39.0%	19.8%	42.3%
2018	Apr	124.8	266.5	232.3	639.6	36.3%	19.5%	41.7%
2018	May	124.7	275.7	223.0	639.6	34.9%	19.5%	43.1%
2018	Jun	136.0	298.4	241.5	696.8	34.7%	19.5%	42.8%
2018	Jul	138.5	294.6	248.3	696.9	35.6%	19.9%	42.3%
2018	Aug	159.6	274.3	271.6	697.0	39.0%	22.9%	39.4%
2018	Sep	150.1	256.7	251.4	644.3	39.0%	23.3%	39.8%
2018	Oct	148.0	266.6	256.6	639.6	40.1%	23.1%	41.7%
2018	Nov	144.0	252.9	274.8	640.4	42.9%	22.5%	39.5%
2018	Dec	172.0	273.0	308.5	674.0	45.8%	25.5%	40.5%
2018 Average		140.5	263.8	254.2	663.0	38.4%	20.8%	41.2%

Increased self scheduled regulation lowers the requirement for cleared regulation, resulting in fewer MW cleared in the market and lower clearing prices. Of the LSEs' obligation to provide regulation in 2018, 60.4 percent was purchased in the PJM market, 34.2 percent was self scheduled, and 5.3 percent was purchased bilaterally (Table 10-40). Table 10-41 shows the total regulation by source including spot market regulation, self scheduled regulation, and bilateral regulation for each year from 2012 to 2018. Table 10-40 and Table 10-41 are based on settled (purchased) MW.

Table 10-40 Regulation sources: spot market, self scheduled, bilateral purchases: 2017 through 2018

Year	Month	Spot Market Regulation (Unadjusted MW)	Spot Market Percent of Total	Self Scheduled Regulation (Unadjusted MW)	Self Scheduled Percent of Total	Bilateral Regulation (Unadjusted MW)	Bilateral Percent of Total	Total Regulation (Unadjusted MW)
2017	Jan	181,386.7	45.8%	188,924.6	47.7%	25,490.5	6.4%	395,801.8
2017	Feb	179,488.3	50.4%	154,308.8	43.3%	22,371.0	6.3%	356,168.1
2017	Mar	174,026.3	46.3%	177,638.3	47.3%	23,963.0	6.4%	375,627.5
2017	Apr	206,895.4	55.7%	145,424.6	39.1%	19,207.5	5.2%	371,527.5
2017	May	212,510.8	57.8%	139,361.6	37.9%	15,967.5	4.3%	367,839.9
2017	Jun	221,942.4	57.5%	142,537.9	36.9%	21,535.0	5.6%	386,015.3
2017	Jul	227,034.0	55.8%	152,610.9	37.5%	27,183.5	6.7%	406,828.4
2017	Aug	238,692.9	59.2%	141,756.7	35.1%	22,844.5	5.7%	403,294.0
2017	Sep	206,361.1	58.1%	130,432.8	36.7%	18,197.0	5.1%	354,990.9
2017	Oct	213,228.1	58.3%	136,134.9	37.2%	16,631.0	4.5%	365,994.1
2017	Nov	201,998.5	57.5%	132,863.4	37.8%	16,257.5	4.6%	351,119.3
2017	Dec	233,931.8	59.1%	141,051.3	35.7%	20,536.5	5.2%	395,519.6
Total		2,497,496.2	55.1%	1,783,045.7	39.4%	250,184.5	5.5%	4,530,726.5
2018	Jan	241,090.6	60.6%	134,251.7	33.7%	22,447.0	5.6%	397,789.2
2018	Feb	221,617.9	61.9%	120,581.1	33.7%	15,846.5	4.4%	358,045.5
2018	Mar	213,227.4	57.0%	141,161.2	37.7%	19,749.0	5.3%	374,137.6
2018	Apr	221,787.2	60.9%	125,524.8	34.5%	16,941.5	4.7%	364,253.5
2018	May	237,448.1	64.3%	115,879.6	31.4%	15,670.0	4.2%	368,997.7
2018	Jun	253,593.9	64.5%	120,041.8	30.5%	19,547.5	5.0%	393,183.2
2018	Jul	259,675.4	63.3%	128,317.0	31.3%	22,103.0	5.4%	410,095.4
2018	Aug	247,312.4	60.3%	132,757.8	32.4%	29,987.0	7.3%	410,057.2
2018	Sep	226,706.5	63.0%	117,025.7	32.5%	16,302.0	4.5%	360,034.2
2018	Oct	220,820.1	59.8%	129,259.5	35.0%	19,042.5	5.2%	369,122.0
2018	Nov	196,182.7	54.8%	136,240.8	38.0%	25,716.0	7.2%	358,139.5
2018	Dec	213,255.5	54.6%	157,304.7	40.3%	20,237.5	5.2%	390,797.7
Total		2,752,717.6	60.4%	1,558,345.7	34.2%	243,589.5	5.3%	4,554,652.8

Table 10-41 Regulation sources: 2012 through 2018

Year	Spot Market Regulation (Unadjusted MW)	Spot Market Percent of Total	Self Scheduled Regulation (Unadjusted MW)	Self Scheduled Percent of Total	Bilateral Regulation (Unadjusted MW)	Bilateral Percent of Total	Total Regulation (Unadjusted MW)
2012	6,149,110.0	78.6%	1,484,446.2	19.0%	193,408.0	2.5%	7,826,964.2
2013	3,088,963.1	57.7%	2,064,156.7	38.5%	204,260.5	3.8%	5,357,380.3
2014	2,327,322.4	49.3%	2,161,996.5	45.8%	231,218.0	4.9%	4,720,536.9
2015	2,546,688.3	54.4%	1,888,040.0	40.3%	250,386.1	5.3%	4,685,114.3
2016	2,260,701.6	48.6%	2,104,775.1	45.2%	287,809.5	6.2%	4,653,286.2
2017	2,497,496.2	55.1%	1,783,045.7	39.4%	250,184.5	5.5%	4,530,726.5
2018	2,752,717.6	60.4%	1,558,345.7	34.2%	243,589.5	5.3%	4,554,652.8

In 2018, DR provided an average of 13.3 MW of regulation per hour during ramp hours (8.5 MW of regulation per hour during ramp hours in 2017), and an average of 11.8 MW of regulation per hour during nonramp hours (7.5 MW of regulation per hour during off peak hours in 2017). Generating units supplied an average of 736.4 MW of regulation per hour during ramp hours in 2018 (711.5 MW of regulation per hour during ramp hours in 2017), and an average of 471.1 MW per hour during nonramp hours in 2018 (480.4 MW of regulation per hour during nonramp hours in 2017).

Market Performance

Price

Table 10-45 shows the regulation price and regulation cost per MW for each year from 2009 through 2018. The weighted average RMCP for 2018 was $25.33 per MW. This is an increase of $8.55 per MW, or 50.9 percent, from the weighted average RMCP of $16.78 per MW in 2017. This increase in the regulation clearing price was the result of an increase in energy prices in 2018 and the related increase in the opportunity cost component of RMCP. The decrease in self supply and $0.00 offers from RegD resources since 2016 also contributed to higher prices.

Figure 10-22 shows the daily weighted average regulation market clearing price and the opportunity cost component for the PJM Regulation Market on a performance adjusted MW basis. This data is based on actual five minute interval operational data. The increase in January was the result of increases in energy prices and the corresponding increase in the opportunity cost component of the RMCP.

Figure 10-22 illustrates that the opportunity cost (blue line) is the largest component of the clearing price.

Figure 10-22 Regulation market-clearing price, opportunity cost and offer price components (Dollars per MW): 2018

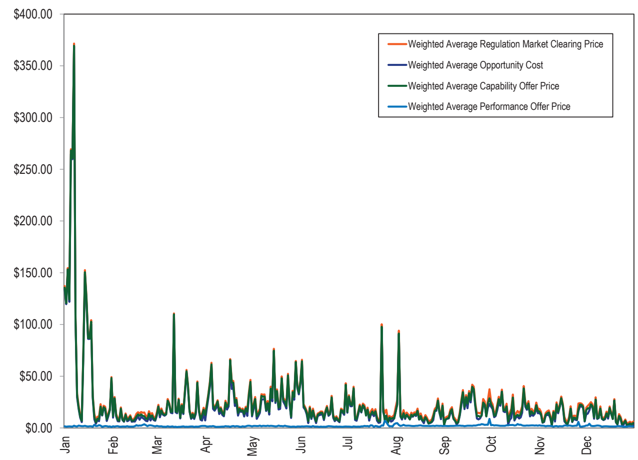


Table 10-42 shows the capability and performance components of the monthly average regulation prices. These components differ from the components of the marginal unit's offers in Figure 10-22 because the performance component of the settlement price for each hour is determined from the average of the highest performance offers in each five minute interval, calculated independent of the marginal unit's offers in those intervals.

Table 10-42 PJM regulation market monthly component of price (Dollars per MW): 2018

Month	Weighted Average Regulation Market Capability Clearing Price ($/Perf. Adj. Actual MW)	Weighted Average Regulation Market Performance Clearing Price ($/Perf. Adj. Actual MW)	Weighted Average Regulation Market Clearing Price ($/Perf. Adj. Actual MW)
Jan	$79.12	$1.72	$80.84
Feb	$10.91	$1.90	$12.80
Mar	$22.36	$1.36	$23.73
Apr	$26.16	$1.54	$27.70
May	$29.09	$1.75	$30.84
Jun	$17.26	$1.38	$18.64
Jul	$17.40	$2.02	$19.42
Aug	$14.92	$2.31	$17.22
Sep	$18.34	$2.58	$20.92
Oct	$18.27	$2.54	$20.81
Nov	$13.24	$2.05	$15.28
Dec	$11.61	$1.78	$13.39
Average	$23.22	$1.91	$25.13

Monthly, total annual, and total year to date scheduled regulation MW and regulation charges, as well as monthly and monthly average regulation price and regulation cost are shown in Table 10-43. Total scheduled regulation is based on settled performance adjusted MW. The total of all regulation charges for 2018 was $145.5 million, compared to $104.4 million for 2017.

Table 10-43 Total regulation charges: 2017 through 2018

Year	Month	Scheduled Regulation (MW)	Total Regulation Charges ($)	Weighted Average Regulation Market Price ($/MW)	Cost of Regulation ($/MW)	Price as Percent of Cost
2017	Jan	395,801.8	$6,867,859	$14.08	$17.35	81.2%
2017	Feb	356,168.1	$5,351,147	$11.12	$15.02	74.0%
2017	Mar	375,627.5	$8,604,989	$16.32	$22.91	71.2%
2017	Apr	371,527.5	$9,057,296	$16.21	$24.38	66.5%
2017	May	367,839.9	$8,949,242	$18.85	$24.33	77.5%
2017	Jun	386,015.3	$7,729,571	$13.85	$20.02	69.1%
2017	Jul	406,828.4	$8,698,583	$15.66	$21.38	73.3%
2017	Aug	403,294.0	$8,396,208	$13.70	$20.82	65.8%
2017	Sep	354,990.9	$10,511,205	$21.98	$29.61	74.2%
2017	Oct	365,994.1	$8,807,785	$16.96	$24.07	70.5%
2017	Nov	351,119.3	$7,994,687	$16.65	$22.77	73.1%
2017	Dec	395,432.9	$13,406,934	$26.06	$33.90	76.9%
Yearly		4,530,745.1	$104,386,359	$16.78	$23.04	72.8%
2018	Jan	397,789.2	$39,129,936	$80.83	$98.37	82.2%
2018	Feb	358,045.5	$6,260,199	$12.81	$17.48	73.2%
2018	Mar	374,137.6	$10,735,239	$23.73	$28.69	82.7%
2018	Apr	364,253.5	$12,882,261	$27.70	$35.37	78.3%
2018	May	368,997.7	$14,087,966	$30.84	$38.18	80.8%
2018	Jun	393,183.2	$8,933,758	$18.64	$22.72	82.0%
2018	Jul	410,095.4	$9,716,064	$19.42	$23.69	82.0%
2018	Aug	410,057.2	$9,079,650	$17.22	$22.14	77.8%
2018	Sep	360,034.2	$9,660,676	$20.92	$26.83	78.0%
2018	Oct	369,122.0	$10,333,629	$20.81	$28.00	74.3%
2018	Nov	358,139.5	$7,528,217	$15.28	$21.02	72.7%
2018	Dec	390,797.7	$7,118,344	$13.39	$18.21	73.5%
Yearly		4,554,652.8	$145,465,939	$25.33	$31.94	79.3%

The capability, performance, and opportunity cost components of the cost of regulation are shown in Table 10-44. Total scheduled regulation is based on settled performance adjusted MW. In 2018, the average total cost of regulation was $31.94 per MW, 38.62 percent higher than $23.04 in 2017. In 2018, the monthly average capability component cost of regulation was $24.22, 68.62 percent higher than $14.36 in 2017. In 2018, the monthly average performance component cost of regulation was $3.63, 46.15 percent lower than $6.75 in 2017.

Table 10-44 Components of regulation cost: 2017 through 2018

Year	Month	Scheduled Regulation (MW)	Cost of Regulation Capability ($/MW)	Cost of Regulation Performance ($/MW)	Opportunity Cost ($/MW)	Total Cost ($/MW)
2017	Jan	395,801.8	$13.19	$2.43	$1.73	$17.35
	Feb	356,168.1	$9.91	$3.68	$1.43	$15.02
	Mar	375,627.5	$13.93	$6.99	$1.98	$22.91
	Apr	371,527.5	$12.94	$9.78	$1.66	$24.38
	May	367,839.9	$16.77	$5.78	$1.78	$24.33
	Jun	386,015.3	$10.81	$7.95	$1.26	$20.02
	Jul	406,828.4	$13.19	$6.37	$1.82	$21.38
	Aug	403,294.0	$10.10	$9.34	$1.38	$20.82
	Sep	354,990.9	$18.83	$8.82	$1.96	$29.61
	Oct	365,994.1	$13.88	$8.51	$1.67	$24.07
	Nov	351,138.0	$14.55	$6.12	$2.09	$22.77
	Dec	395,519.6	$24.35	$5.29	$4.29	$33.92
Yearly		4,530,745.1	$14.36	$6.75	$1.93	$23.04
2018	Jan	397,789.2	$80.32	$3.76	$14.29	$98.37
	Feb	358,045.5	$11.17	$4.47	$1.84	$17.48
	Mar	374,137.6	$22.92	$2.91	$2.86	$28.69
	Apr	364,253.5	$26.78	$3.57	$5.02	$35.37
	May	368,997.7	$29.85	$3.78	$4.55	$38.18
	Jun	393,183.2	$17.76	$2.92	$2.04	$22.72
	Jul	410,095.4	$18.25	$3.08	$2.36	$23.69
	Aug	410,057.2	$16.04	$3.48	$2.62	$22.14
	Sep	360,034.2	$19.46	$4.15	$3.23	$26.83
	Oct	369,122.0	$19.20	$4.99	$3.81	$28.00
	Nov	358,139.5	$14.20	$3.36	$3.46	$21.02
	Dec	390,797.7	$12.31	$3.29	$2.61	$18.21
Yearly		4,554,652.8	$24.22	$3.63	$4.08	$31.94

Table 10-45 provides a comparison of the average price and cost for PJM regulation. The ratio of regulation market price to the cost of regulation in 2018 was 79.3 percent, an 8.9 percent increase from 72.8 percent in 2017.

Table 10-45 Comparison of average price and cost for PJM regulation: 2009 through 2018

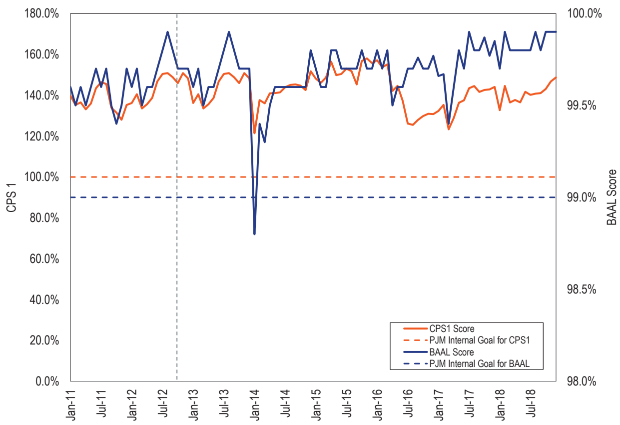
Year	Weighted Regulation Market Price	Weighted Regulation Market Cost	Regulation Price as Percent Cost
2009	$23.00	$30.68	75.0%
2010	$18.00	$32.86	54.8%
2011	$16.49	$29.72	55.5%
2012	$19.02	$25.32	75.1%
2013	$30.85	$35.79	86.2%
2014	$44.49	$53.82	82.7%
2015	$31.92	$38.36	83.2%
2016	$15.73	$18.13	86.7%
2017	$16.78	$23.04	72.8%
2018	$25.33	$31.94	79.3%

Performance Standards

PJM's performance as measured by CPS1 and BAAL standards is shown in Figure 10-23 for every month from January 2011 through December 2018 with the dashed vertical line marking the date (October 1, 2012) of the implementation of the Performance Based Regulation Market design.[88] The horizontal dashed lines represent PJM internal goals for CPS1 and BAAL performance. While PJM did not meet its internal goal for BAAL performance in January 2014, PJM remained in compliance with the applicable NERC standards.

88 See *2018 State of the Market Report for PJM*, Appendix F: Ancillary Services.

Figure 10-23 PJM monthly CPS1 and BAAL performance: 2011 through 2018



Black Start Service

Black start service is necessary to ensure the reliable restoration of the grid following a blackout. Black start service is the ability of a generating unit to start without an outside electrical supply, or the demonstrated ability of a generating unit to automatically remain operating when disconnected from the grid.

PJM does not have a market to provide black start service, but compensates black start resource owners on the basis of an incentive rate or for the costs associated with providing this service.

PJM defines required black start capability zonally, while recognizing that the most effective way to provide black start service may be across zones, and ensures the availability of black start service by charging transmission customers according to their zonal load ratio share and compensating black start unit owners. Substantial rule changes to the black start restoration and procurement strategy were implemented on February 28, 2013, following a stakeholder process in the System Restoration Strategy Task Force (SRSTF) and the Markets and Reliability Committee (MRC) that approved the PJM and MMU joint proposal for system restoration. These changes gave PJM substantial flexibility in procuring black start resources and made PJM responsible for black start resource selection.

On July 1, 2013, PJM initiated its first RTO-wide request for proposals (RFP) under the new rules.[89] [90] PJM identified zones with black start shortages and began awarding contracts on January 14, 2014. PJM and the MMU coordinated closely during the selection process.

PJM issued two additional RFPs in 2014. On April 11, 2014, PJM sought additional black start in the AEP Zone and one proposal was selected. On November 24, 2014, PJM sought additional black start in Northeastern Ohio and Western Pennsylvania, but no proposals were selected because they did not meet the bid requirements. On July 28, 2015, PJM issued an Incremental Request for Proposals, for Northeastern Ohio and Western Pennsylvania together. On August 8, 2016, PJM made one award which will cover both areas.

On February 1, 2018, PJM issued its second RTO wide request for proposals (RFP) in accordance with the five year black start selection process. The RFP process is a two–tiered process. Level one submissions were due March 8, 2018. On March 30, 2018, PJM notified participants if a level two response would be requested. Level two bidders were requested by PJM to provide their detailed proposal by May 31, 2018. From November 28, 2018, through December 21, 2018, PJM awarded seven proposals.

Total black start charges are the sum of black start revenue requirement charges and black start operating reserve charges. Black start revenue requirements for black start units consist of fixed black start service costs, variable black start service costs, training costs, fuel storage costs, and an incentive factor. Section 18 of Schedule 6A of the OATT specifies how to calculate each component of the revenue requirement formula. Black start resources can choose to recover fixed costs under a formula rate based on zonal Net CONE and unit ICAP rating, a cost recovery rate based on incremental black start NERC-CIP compliance capital costs, or a cost recovery rate based on incremental black start equipment capital costs. Black start operating reserve charges are paid to units scheduled in the Day-Ahead Energy Market or committed in real time to provide black start service under the automatic load rejection (ALR) option or for

89 See PJM. "RTO-Wide Five-Year Selection Process Request for Proposal for Black Start Service," (July 1, 2013).

90 RFPs issued can be found on the PJM website. See PJM. <http://www.pjm.com/markets-and-operations/ancillary-services.aspx>.

black start testing. Total black start charges are allocated monthly to PJM customers proportionally to their zone and nonzone peak transmission use and point to point transmission reservations.[91]

In 2018, total black start charges were $64.747 million, a decrease of $4.769 million (-6.9 percent) from the same period in 2017. Operating reserve charges for black start service increased from $0.257 million in 2017 to $0.303 million in 2018. Table 10-46 shows total revenue requirement charges from 2010 through 2018. Prior to December 2012, PJM did not define a separate black start operating reserve category. Starting December 1, 2012, PJM defined a separate black start operating reserve category. By April 2015, all ALR units had been replaced and no longer provided black start service which resulted in decreased operating reserve charges.

Table 10-46 Black start revenue requirement charges: 2010 through 2018

Year	Revenue Requirement Charges	Operating Reserve Charges	Total
2010	$11,490,379	$0	$11,490,379
2011	$13,695,331	$0	$13,695,331
2012	$18,749,617	$8,384,651	$27,134,269
2013	$20,874,535	$86,701,561	$107,576,097
2014	$26,945,112	$32,906,733	$59,851,845
2015	$56,425,648	$5,175,644	$61,601,292
2016	$69,376,257	$279,017	$69,655,275
2017	$69,258,169	$257,174	$69,515,342
2018	$64,443,593	$303,184	$64,746,777

Black start zonal charges in 2018 ranged from $0.07 per MW-day in the DLCO Zone (total charges were $72,167) to $4.26 per MW-day in the PENELEC Zone (total charges were $4,496,206). For each zone, Table 10-47 shows black start charges, the sum of monthly zonal peak loads multiplied by the number of days of the month in which the peak load occurred, and black start rates (calculated as charges per MW-day). For black start service, point to point transmission customers paid on average $1.12 per MW day of reserve capacity during 2018.

Table 10-47 Black start zonal charges for network transmission use: 2017 and 2018[92]

	2017						2018					
Zone	Revenue Requirement Charges	Operating Reserve Charges	Total Charges	Peak Load (MW)	Days	Black Start Rate ($/MW-day)	Revenue Requirement Charges	Operating Reserve Charges	Total Charges	Peak Load (MW)	Days	Black Start Rate ($/MW-day)
AECO	$2,689,333	$9,974	$2,699,307	2,673	365	$2.77	$2,715,114	$14,518	$2,729,632	2,541	365	$2.94
AEP	$17,515,655	$38,221	$17,553,876	22,474	365	$2.14	$17,460,948	$40,684	$17,501,632	21,647	365	$2.22
APS	$3,863,022	$1,394	$3,864,416	8,717	365	$1.21	$3,909,172	$3,945	$3,913,116	8,755	365	$1.22
ATSI	$3,025,757	$0	$3,025,757	12,752	365	$0.65	$3,064,308	$934	$3,065,242	12,052	365	$0.70
BGE	$4,180,070	$3,310	$4,183,379	6,601	365	$1.74	$1,050,713	$3,371	$1,054,084	6,448	365	$0.45
ComEd	$4,889,894	$21,923	$4,911,817	21,175	365	$0.64	$4,516,877	$15,937	$4,532,813	20,351	365	$0.61
DAY	$255,338	$9,966	$265,304	3,342	365	$0.22	$230,458	$2,330	$232,789	3,225	365	$0.20
DEOK	$1,043,068	$3,622	$1,046,690	5,308	365	$0.54	$749,240	$1,959	$751,198	5,036	365	$0.41
DLCO	$51,114	$12,906	$64,020	2,797	365	$0.06	$48,258	$23,909	$72,167	2,682	365	$0.07
Dominion	$4,297,174	$33,766	$4,330,940	19,538	365	$0.61	$3,931,631	$23,354	$3,954,985	19,661	365	$0.55
DPL	$2,280,454	$7,735	$2,288,189	4,127	365	$1.52	$2,246,697	$9,602	$2,256,299	3,813	365	$1.62
EKPC	$414,454	$0	$414,454	2,878	365	$0.39	$369,857	$844	$370,702	2,860	365	$0.36
JCPL	$6,821,817	$9,358	$6,831,175	5,955	365	$3.14	$6,814,859	$9,035	$6,823,894	5,721	365	$3.27
Met-Ed	$607,876	$65,332	$673,209	2,947	365	$0.63	$566,537	$107,889	$674,426	2,897	365	$0.64
PECO	$1,643,443	$1,777	$1,645,220	8,364	365	$0.54	$1,509,876	$2,460	$1,512,336	8,141	365	$0.51
PENELEC	$4,543,929	$1,623	$4,545,552	2,909	365	$4.28	$4,492,887	$3,319	$4,496,206	2,890	365	$4.26
Pepco	$2,521,020	$16,114	$2,537,133	6,584	365	$1.06	$2,505,653	$17,171	$2,522,824	6,097	365	$1.13
PPL	$1,211,901	$5,547	$1,217,448	7,025	365	$0.47	$1,180,925	$7,873	$1,188,798	7,401	365	$0.44
PSEG	$4,180,537	$2,805	$4,183,342	9,800	365	$1.17	$4,202,903	$861	$4,203,765	9,567	365	$1.20
RECO	$0	$0	$0	NA	365	NA	$0	$0	$0	NA	365	NA
(Imp/Exp/Wheels)	$3,222,313	$11,802	$3,234,114	7,617	365	$1.16	$2,876,681	$13,188	$2,889,869	7,121	365	$1.11
Total	$69,258,169	$257,174	$69,515,342	163,583		$1.16	$64,443,593	$303,184	$64,746,777	158,906		$1.12

91 OATT Schedule 6A (paras. 25, 26 and 27 outline how charges are to be applied).
92 Peak load for each zone is used to calculate the black start rate per MW day.

Table 10-48 provides a revenue requirement estimate by zone for the 2018/2019, 2019/2020 and 2020/2021 delivery years.[93] Revenue requirement values are rounded up to the nearest $50,000 to reflect uncertainty about future black start revenue requirement costs. These values are illustrative only. The estimates are based on the best available data including current black start unit revenue requirements, expected black start unit termination and in-service dates, changes in recovery rates, and owner provided cost estimates of incoming black start units at the time of publication and may change significantly. Prior to November 26, 2017, new black start units were not paid until their costs had been provided with appropriate support and approved. In some cases black start units were completed and went into service before costs had been supported and therefore costs were not approved. In these cases the unit did not receive any payments until the costs were appropriately supported. Once their costs were approved the units received all payments going back to the in service date. The result was a lumpy payment by load for black start service. After November 26, 2017, PJM accrued payments for the black start units each month, until the units costs were supported and approved in order to smooth out monthly payments for black start service.

Table 10-48 Black start zonal revenue requirement estimate: 2018/2019 through 2020/2021 delivery years

Zone	2018 / 2019 Revenue Requirement	2019 / 2020 Revenue Requirement	2020 / 2021 Revenue Requirement
AECO	$2,900,000	$2,800,000	$2,700,000
AEP	$18,200,000	$18,800,000	$21,550,000
APS	$4,150,000	$4,150,000	$5,550,000
ATSI	$4,150,000	$5,850,000	$5,850,000
BGE	$450,000	$350,000	$50,000
ComEd	$4,450,000	$5,650,000	$10,100,000
DAY	$250,000	$250,000	$250,000
DEOK	$500,000	$400,000	$400,000
DLCO	$50,000	$50,000	$50,000
Dominion	$3,750,000	$4,300,000	$5,700,000
DPL	$2,400,000	$2,350,000	$2,350,000
EKPC	$350,000	$350,000	$350,000
JCPL	$7,150,000	$7,100,000	$750,000
Met-Ed	$550,000	$500,000	$450,000
OVEC	$0	$0	$0
PECO	$1,450,000	$1,450,000	$1,450,000
PENELEC	$4,650,000	$4,600,000	$4,600,000
Pepco	$2,600,000	$2,600,000	$700,000
PPL	$1,250,000	$1,750,000	$4,400,000
PSEG	$4,400,000	$4,400,000	$1,850,000
RECO	$0	$0	$0
Total	$63,650,000	$67,700,000	$69,100,000

93 The System Restoration Strategy Task Force requested that the MMU provide estimated black start revenue requirements.

NERC – CIP

Currently, no black start units have requested new or additional black start NERC – CIP Capital Costs.[94]

Minimum Tank Suction Level (MTSL)

Some units that participate in the PJM energy market have oil tanks. All oil tanks at PJM units have a MTSL regardless of whether the units provide black start service (unless they use direct current pumps). The MTSL is the amount of fuel at the bottom of a tank which cannot be recovered for use.

PJM has required that customers pay black start unit owners carrying cost recovery for one hundred percent of the MTSL for tanks which are shared with units in the energy market. These tanks were sized to meet the needs of the generating units, which use significantly more fuel than the black start units. In some instances the MTSL is greater than the total amount of fuel that the black start unit needs to operate to meet its black start obligations. When a black start diesel is added at the site of an oil-fired generating unit, the additional MTSL is zero.

Figure 10-24 illustrates that the size of the oil tank does not change with the addition of the black start unit. Figure 10-25 shows how the MTSL could be proportionally divided between the generator and the black start unit. The tank is 4,000,000 gallons with an MTSL of 800,000 gallons leaving 3,200,000 gallons of usable fuel. The black start unit running 16 hours using 12,000 gallons per hour would need a total of 192,000 gallons, or six percent of the total usable fuel. Assigning six percent of the MTSL (800,000 gallons) would yield 48,000 gallons which could be assigned to the black start proportion for the MTSL.

The MMU recommends that for oil tanks which are shared with other resources that only a proportionate share of the MTSL be allocated for black start units. The MMU further recommends that the PJM tariff be updated to clearly state how the MTSL will be calculated for black start units sharing oil tanks.

94 OATT Schedule 6A para. 21. "The Market Monitoring Unit shall include a Black Start Service summary in its annual State of the Market report which will set forth a descriptive summary of the new or additional Black Start NERC-CIP Capital costs requested by Black Start Units, and include a list of the types of capital costs requested and the overall cost of such capital improvements on an aggregate basis such that no data is attributable to an individual Black Start Unit."

Figure 10-24 Oil tank MTSL not changed from addition of black start generator

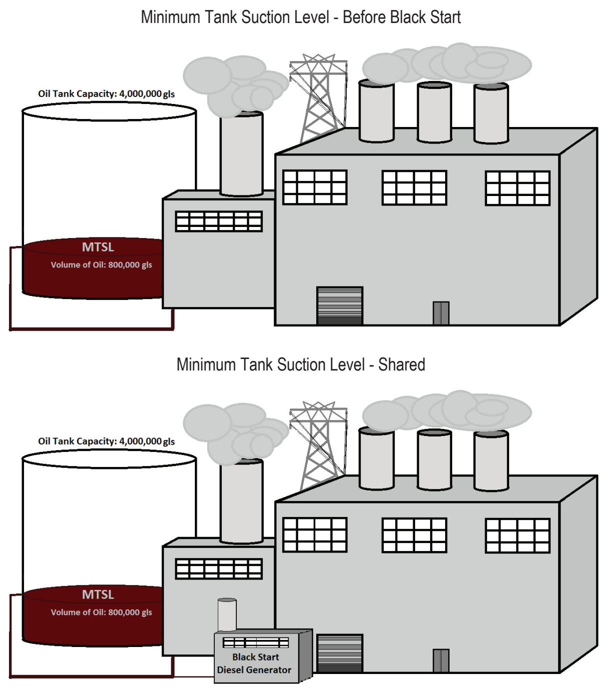
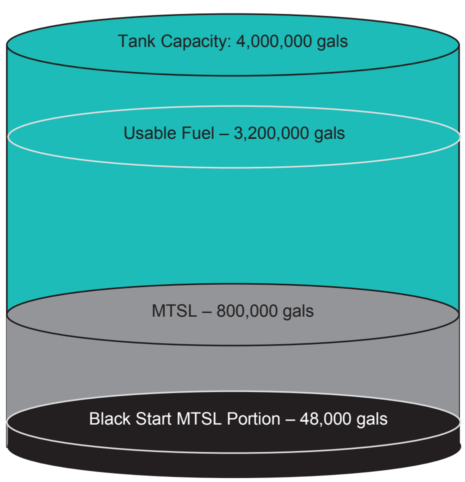


Figure 10-25 Oil tank black start MTSL portion



Reactive Service

Suppliers of reactive power are compensated separately for reactive capability, day-ahead operating reserves, and for real-time lost opportunity costs. Compensation for reactive capability must be approved separately for each resource or resource group by FERC per Schedule 2 of the OATT. Resources may obtain FERC approval to recover a share of resources' fixed costs by calculating a reactive revenue requirement, the reactive capability rate, and to collect such rates from PJM transmission customers.[95]

Any reactive service provided operationally that involves a MW reduction outside of its normal operating range or a startup for reactive power will be logged by PJM operators and awarded uplift or LOC credits.

Reactive Service, Reactive Supply and Voltage Control are provided by generation and other sources of reactive power (such as static VAR compensators and capacitor banks).[96] While a fixed requirement for reactive power is not established, reactive power helps maintain appropriate voltages on the transmission system and must be sourced locally.

Total reactive capability charges are the sum of FERC approved reactive supply revenue requirements which are posted monthly on the PJM website.[97] Zonal reactive supply revenue requirement charges are allocated monthly to PJM customers proportionally to their zone and to any nonzone (i.e. outside of the PJM Region) peak transmission use and point to point transmission reservations.[98]

In 2016, the FERC began to reexamine its policies on reactive compensation.[99] Changes in the default capabilities of generators, disparities between nameplate values and tested values and questions about the way the allocation factors have been calculated have called continued reliance on the AEP method into question.[100]

95 See "PJM Manual 27: Open Access Transmission Tariff Accounting,"§ 3.2 Reactive Supply and Voltage Control Credits, Rev. 90, (Dec. 6, 2018).
96 OATT Schedule 2.
97 See PJM. Markets & Operations: Billing, Settlements & Credit, "Reactive Revenue Requirements,"<http://www.pjm.com/~/media/markets-ops/settlements/reactive-revenue-requirements-table-may-2016.ashx> (June 8, 2016).
98 OATT Schedule 2.
99 See *Reactive Supply Compensation in Markets Operated by Regional Transmission Organizations and Independent System Operators*, Docket No. AD16-17-000 (March 17, 2016) (Notice of Workshop).
100 See 88 FERC ¶ 61,141 (1999).

The continued use of fleet rates rather than unit specific rates is also an issue.

Recommended Market Approach to Reactive Costs

The best approach for recovering reactive capability costs is through markets where markets are available as they are in PJM and some other RTOs/ISOs. The best approach for recovering reactive capability costs in PJM is through the capacity market. The capacity market already incorporates reactive costs and reactive revenues. The treatment of reactive costs in the PJM market needs to be modified so that the capacity market incorporates reactive costs and revenues in a more efficient manner.

Reactive capability is an integral part of all generating units; no generating unit is built without reactive capability.[101] There is no reason that the fixed costs of reactive capability either can be or should be separated from the total fixed costs of a generating unit. There is no reason that reactive capability should be compensated outside the markets when the units participate in organized markets. Reactive capability is a precondition for participating in organized markets. Resources must invest in the equipment needed to have minimum reactive capability as a condition of receiving interconnection service from PJM and other markets.[102] The Commission has recently extended the interconnection service requirement to have reactive capability to wind and solar units, which previously had been exempt.[103] Reactive capability is a requirement for participating in organized markets and is therefore appropriately treated as part of the gross Cost of New Entry in organized markets.

PJM requires a power factor of at least 0.95 leading to 0.90 lagging for synchronous units and at least 0.95 leading to 0.95 lagging for nonsynchronous units.[104] The regulations specify a minimum power factor range of 0.95 leading and 0.95 lagging power factor unless the market operators' rules specify otherwise.[105]

There are two ways to address the cost of reactive in the PJM market design.

Under the current capacity market rules, the gross costs of the entire plant, including any reactive costs, are included in the gross Cost of New Entry (CONE) and the revenues from reactive service capability rates are an offset to the gross CONE. The result is that, conceptually, the cost of reactive is not part of net CONE.[106] This is logically consistent with the separate collection of reactive costs through a cost of service rate in that there is no double counting if the revenue offset is done accurately. Under this approach there is a separate collection of reactive capability costs. This approach also requires that any capacity resource calculating unit specific net revenues must include the cost of service reactive revenues in the calculation. In fact, the revenue offset is defined as a fixed number in the PJM tariff and does not correctly reflect the current revenue requirement of a new unit.

An alternative approach to the current treatment of reactive costs in the capacity market would be to include the gross costs of the entire plant including any reactive costs in the gross Cost of New Entry (CONE) but to calculate net CONE without a reactive revenue offset for reactive service capability rates. The result of this approach would be that the cost of reactive is part of net CONE. This is logically consistent with the elimination of the separate collection of reactive costs through a cost of service rate in that there is no double counting if done accurately. Under this approach there would be no separate collection of reactive capability costs.

PJM currently uses the first approach. There is no reason that PJM could not easily implement the second approach.

The second approach is preferable. The second approach relies on competitive markets to provide incentives to provide energy, both real and reactive, at the lowest

101 See Order No. 827, 155 FERC ¶ 61,277 at P 9 (2016) ("[T]he equipment needed for a wind generator to provide reactive power has become more commercially available and less costly, such that the cost of installing equipment that is capable of providing reactive power is comparable to the costs of a traditional generator.").

102 See 18 CFR § 35.28(f)(1); Order No. 2003, FERC Stats. & Regs. ¶ 31,146, Appendix G (Large Generator Interconnection Agreement (LGIA)), *order on reh'g*, Order No. 2003-A, FERC Stats. & Regs. ¶ 31,160, *order on reh'g*, Order No. 2003-B, FERC Stats. & Regs. ¶ 31,171 (2004), *order on reh'g*, Order No. 2003-C, FERC Stats. & Regs. ¶ 31,190 (2005), *aff'd sub nom.* Nat'l Ass'n of Regulatory Util. Comm'rs v. FERC, 475 F.3d 1277 (D.C. Cir. 2007), *cert. denied*, 552 U.S. 1230 (2008); Order No. 2006, FERC Stats. & Regs. ¶ 31,180, Attachment F (Small Generator Interconnection Agreement), *order on reh'g*, Order No. 2006-A, FERC Stats. & Regs. ¶ 31,196 (2005), *order granting clarification*, Order No. 2006-B, FERC Stats. & Regs. ¶ 31,221 (2006).

103 Order No. 827, 155 FERC ¶ 61,277 (2016); *see also* 151 FERC ¶ 61,097 at P 28 (2015).

104 See OATT Attachment O Appendix 2 § 4.7.

105 See LGIA Article 9.6.1 ("Interconnection Customer shall design the Large Generating Facility to maintain a composite power delivery at continuous rated power output at the Point of Interconnection at a power factor within the range of 0.95 leading to 0.95 lagging, unless Transmission Provider has established different requirements that apply to all generators in the Control Area on a comparable basis.").

106 See OATT Attachment DD § 5.10(a)(iv).

possible cost. The second approach provides a consistent and nondiscriminatory approach to compensation, avoiding reliance on a large number of costly and sporadic ratemaking proceedings. The second approach does not require the use of arbitrary, approximate and generally inaccurate allocators to determine the cost of providing reactive. The second approach does not require the use of estimated, average and inaccurate net reactive revenue offsets to calculate Net CONE. It is critical in the PJM Capacity Market that Net CONE be as accurate as possible. Only the second approach assures this.

Units are compensated for reactive capability costs under the second approach. But the compensation is based on the outcome of a competitive capacity market rather than based on current or historical cost of service filings for units or fleets of units.

The first approach, although internally logically consistent, relies on unnecessary and inaccurate approximations. The reactive allocator is such an approximation. The reactive revenue offset is an inaccurate estimate based on historical data from reactive revenue requirement filings. The reactive revenues used in the net CONE calculation are based on an average of reactive filings over the three years from 2005 through 2007 and therefore do not reflect even the allocated reactive costs and revenues for a new unit, as would be required to be consistent with the CONE logic.[107] To the extent that the reactive portion of the Net Energy and Ancillary Services Offset is inaccurate, the net CONE is inaccurate.

The reactive revenue offset is set equal to $ 2,199/MW-year in the OATT.[108] This figure is the average annual reactive revenue for combustion turbines from 2005 through 2007, based on the actual costs reported to the Commission in reactive service filings of CTs, as developed by the MMU.

The Net Cost of New Entry is a key parameter in the PJM Capacity Market as it affects the location of the VRR or demand curve and thus has a direct impact on capacity market prices.[109]

If revenues for reactive capacity were removed from the Net Energy and Ancillary Services Revenue Offset, then the fixed costs for investment in reactive capability would be recoverable through the capacity market. By employing a simple and direct approach using CONE with no offset, the rules for cost of service compensation included in Schedule 2 could be eliminated and the requirement for cost of service filings would be eliminated.

As a result of the nature of reactive filings, it is not possible to identify the reactive capability revenues for all individual units that receive reactive capability revenues. As a result, the offer caps in the capacity market are not as accurate as they should be.

Relying on capacity markets instead of cost of service allocations would enhance competition and efficient pricing.

Actual experience with the cost of service approach suggests that customers would be better off under a competition based approach. The Commission's recent investigations into particular rates raises questions about the accuracy and basis of rates currently charged for reactive capability.

Cost of service ratemaking creates unnecessary monitoring difficulties. Because service providers do not have to file rates periodically, suppliers have no incentive to adjust reactive capability rates except when they increase. Suppliers have direct access to information about the costs for their own units. The Commission and other parties do not have such access. When rates are established on a fleet basis or result from a black box settlement, the ability of parties to review and challenge rates is further reduced.

The current FERC review provides an excellent opportunity to discard an anachronistic cost of service approach that has not been working well and that is inconsistent with markets and is unnecessary in

107 OATT Attachment DD § 5.10(a)(v)(A) ("The Office of the Interconnection shall determine the Net Energy and Ancillary Services Revenue Offset each year for the PJM Region as (A) the annual average of the revenues that would have been received by the Reference Resource from the PJM energy markets during a period of three consecutive calendar years preceding the time of the determination, based on (1) the heat rate and other characteristics of such Reference Resource; (2) fuel prices reported during such period at an appropriate pricing point for the PJM Region with a fuel transmission adder appropriate for such region, as set forth in the PJM Manuals, assumed variable operation and maintenance expenses for such resource of $6.47 per MWh, and actual PJM hourly average Locational Marginal Prices recorded in the PJM Region during such period; and (3) an assumption that the Reference Resource would be dispatched for both the Day-Ahead and Real-Time Energy Markets on a Peak-Hour Dispatch basis; plus (B) ancillary service revenues of $2,199 per MW-year.").

108 *Id.*

109 *Id.*

organized markets.[110] Increased reliance on markets for the recovery of reactive capability costs would promote efficiency and consistency. Customers, market administrators and regulators will be better served by a simpler and more effective competition based approach.

The MMU recommends that separate payments for reactive capability be eliminated and the cost of reactive capability be recovered in the capacity market.

Improvements to Current Approach

If OATT Schedule 2 reactive capability payments are not eliminated, then the MMU recommends, at a minimum, that steps be taken to ensure that payments are based on capability that is measured in tests performed by PJM or demonstrated in market data showing actual reactive output and based on capability levels that are useful to PJM system operators to maintain system stability. FERC has initiated a number of investigations into the basis for reactive rates, and the MMU has intervened in and is participating in those proceedings.[111]

Under the AEP method, units must establish their MVAR rating based on "the capability of the generators to produce VARs."[112] Typically this has meant reliance on manufacturers' specified nameplate power factor.[113] More recently, the Commission has, in the Wabash Orders, required that "reactive power revenue requirement filings must include reactive power test reports."[114] Noting a difference between tested reactive MVAR ratings and nameplate MVAR ratings, the Commission has, in a number of cases, set the issue of MVAR rating degradation for hearing.[115]

The Commission has identified a significant issue. Tests are essential to "evaluate and analyze" proposed reactive revenue requirements.[116] The MVAR rating has a significant influence on the level of the requirements and should accurately reflect the MVAR capability actually available to maintain reliability.

There is no reason to use the nameplate MVAR rating to develop a reactive allocation and there is no basis in the AEP method for reliance on the nameplate MVAR rating. Nameplate reactive power ratings are generally higher than the actual ratings as defined by the PJM mandated tests of capability because nameplate power ratings are generally calculated using leading and lagging power factors that are lower than are achievable when installed in a specific plant interconnected to a specific transmission network. Although this issue is characterized as degradation, the difference between pre installation nameplate ratings and post installation tested capability exists even when units are new. Testing reveals whether the tested capability changes. Reliance on tested results would address both the issue of degradation and the issue of theoretical versus actual MVAR ratings.

PJM determined in 1999 that nameplate MVAR and power factor ratings do not reflect the value to the system operator of a unit's reactive output after it is interconnected at a specific location. Only operator evaluation of reactive capability can provide a meaningful measure of reactive capability.

The most fundamental point about power factors is that PJM requires that all generating units have a 0.90 power factor in order to obtain interconnection service.[117] There is no reason to pay any provider of reactive capability based on a power factor exceeding the 0.90 power factor that PJM has determined is necessary.

The estimated capability costs also include estimated heating losses relative to MVAR output.[118] Heating losses are variable costs and not fixed costs and should not be included in the definition of reactive capability costs.[119] Heating losses can be accurately calculated for each hour of operation if each unit had an accurate, recent D-curve test. Heating losses are variable costs and should not be included in the cost of reactive capability. The production of reactive power slightly reduces the MWh output of the generator as the generator follows its D-curve. The value of this heating loss component is generally estimated based on estimated operation and associated estimated losses and estimated market

110 See FERC Docket No. AD16-17-000.

111 See e.g., FERC Dockets Nos. EL16-32, EL16-44, EL16-51, EL16-54, EL16-65, EL16-66, EL16-79, EL16-89, EL16-90, EL16-98, EL16-72, EL16-100, EL16-103, EL16-118, EL16-1004, ER16-1456, ER16-2217, EL17-19, EL17-38, EL17-39, EL17-49, ER17-259 and ER17-801.

112 *AEP mimeo* at 31.

113 See, e.g., *id.*

114 154 FERC ¶ 61,246 at P 28 (2016); see also 154 FERC ¶ 61,246 at P 29 (*Wabash* Orders).

115 See, e.g., 154 FERC ¶ 61,087 at P 10 (2016) ("The Informational Filing contains information that raises concerns about the justness and reasonableness of Ironwood's reactive power rate, including, but not limited to, the degradation of the Facility's current MVAR capability as compared with the MVAR capability that was originally used to calculate the revenue requirement for Reactive Service included in Ironwood's reactive power rate.").

116 154 FERC ¶ 61,246 at P 28 (2016); see also 154 FERC ¶ 61,246 at P 29.

117 *See supra* footnote 27.

118 See, e.g., *id.* at P 10 n12, citing *PPL Energy Plus, LLC*, Letter Order, Docket No. ER08-1462-000 (Sept. 24, 2008); 125 FERC ¶ 61,280 at P 35 (2008).

119 See Transcript, *Reactive Supply Compensation in Markets Operated by Regional Transmission System Operators Workshop*, AD16-17-000 (June 30, 2016) at 26:21–27:23.

prices, treated as a fixed cost, and included in the cost of reactive capability. Losses are minimal and occur during normal operations and should not be treated as a fixed cost. Losses can be better and more accurately accounted for as a variable cost based on actual unit operations and market conditions.

Reactive service is supplied during normal operation as needed and directed by PJM dispatchers. Most reactive service is provided with no impact to operational dispatch. When a need for reactive service requires that a unit's MW output be reduced outside of its normal operational range, or when a unit is started to provide reactive power, it is logged by PJM dispatchers and will be paid reactive service credits in the zone or zones where the reactive service was provided proportionally to their zone and nonzone peak transmission use and point to point transmission reservations.

Cost of service rates are established under Schedule 2 of the OATT and may cover rates for single units or a fleet of units.[120] Until the Commission took corrective action, fleet rates remained in place in PJM even when the actual units in the fleet changed as a result of unit retirements or sales of units.[121] New rules require unit owners to give notice of fleet changes in an informational filing or to file a new rate based on the remaining units, but do not yet require unit specific reactive rates.[122] Fleet rates should be eliminated. Compensation should be based on unit specific costs. Fleet rates make it almost impossible to monitor whether compensation for reactive capability is based on actual unit specific performance and costs.

To the extent that the Commission decides that PJM and other markets should continue to rely on a cost of service method to compensate reactive capability, the rules should be modified to improve the accuracy of the calculations of reactive capability cost. Double compensation should not be permitted as a combined result of market based capacity prices and cost of service rates.

Reactive capability rate schedules must be accurate, and they must also coordinate properly with the PJM market rules. Revenues received for reactive capability are revenues for ancillary services that should be netted against avoidable costs whenever avoidable cost rate offers are submitted in RPM capacity market auctions.[123] Participants have not been properly including reactive revenues in capacity market offers, and the MMU has notified participants of its compliance concerns. The identification of revenues for reactive capability on a unit specific basis is necessary for the calculation of accurate avoidable cost rate offers and is needed to avoid disputes that could interfere with the orderly administration of RPM auctions. The MMU has sought to address this issue through participation in proceedings at FERC concerning reactive capability rates for PJM units.[124]

Reactive Costs

In 2018, total reactive charges were $342.0 million, a 3.1 percent increase from the $331.7 million for 2017. Reactive capability revenue requirement charges increased from $311.3 million in 2017 to $328.8 million in 2018 and reactive service charges decreased from $20.4 million in 2017 to $13.1 million in 2018.[125] All $13.1 million in 2018 were paid for reactive service provided by 25 units in 283 hours in specific locations.

Table 10-49 shows reactive service charges in 2017 and 2018, reactive capability revenue requirement charges and total charges. Reactive service charges show charges to each zone for reactive service provided and not credits to plants in each zone. Reactive capability revenue requirement charges show charges to each zone for reactive capability.

120 See, e.g., OATT Schedule 2; 114 FERC ¶ 61,318 (2006).
121 See 149 FERC ¶ 61,132 (2014); 151 FERC ¶ 61,224 (2015); OATT Schedule 2.
122 *Id.*
123 See OATT Attachment DD §§ 6.4, 6.8(d).
124 See, e.g., FERC Dockets Nos. EL16-44 et al.; ER16-1456; EL16-57 et al.; EL16-51 et al.; ER16-1004; EL16-32; EL16-72; EL16-66; EL16-65; EL16-54; EL16-90 et al.; EL16-103 et al.; EL16-89 et al.; EL16-98 et al.; EL16-79 et al.; EL16-80 et al.; EL16-81 et al.; EL16-82 et al.; EL16-83 et al.; ER16-2217 et al.; EL17-19; EL16-118.
125 See *2018 State of the Market Report for PJM*, Section 4, "Energy Uplift."

Table 10-49 Reactive zonal charges for network transmission use: 2017 and 2018

	2017			2018		
Zone	Reactive Service Charges	Reactive Capability Revenue Requirement Charges	Total Charges	Reactive Service Charges	Reactive Capability Revenue Requirement Charges	Total Charges
AECO	$8,686	$4,247,222	$4,255,908	$145	$4,713,244	$4,713,390
AEP	$178,314	$39,234,081	$39,412,395	$775,231	$43,933,120	$44,708,351
APS	$135,676	$16,800,854	$16,936,530	$0	$16,229,147	$16,229,147
ATSI	$77,078	$21,342,021	$21,419,099	$0	$21,913,045	$21,913,045
BGE	$1,694,486	$8,205,331	$9,899,817	$30,956	$8,046,036	$8,076,993
ComEd	$13,242,447	$30,855,459	$44,097,906	$11,335,202	$39,133,222	$50,468,424
DAY	$15,845	$5,628,799	$5,644,643	$0	$4,557,604	$4,557,604
DEOK	$25,386	$8,057,110	$8,082,496	$0	$8,502,164	$8,502,164
Dominion	$120,722	$34,512,902	$34,633,624	$46,914	$38,115,437	$38,162,351
DPL	$1,308,524	$11,512,490	$12,821,014	$257,310	$11,525,471	$11,782,781
DLCO	$12,737	$779,263	$792,000	$0	$780,579	$780,579
EKPC	$20,528	$2,185,849	$2,206,377	$198,562	$2,189,542	$2,388,104
JCPL	$19,441	$8,973,314	$8,992,755	$0	$8,974,083	$8,974,083
Met-Ed	$68,170	$5,198,247	$5,266,417	$0	$4,831,397	$4,831,397
PECO	$103,510	$22,285,794	$22,389,303	$0	$23,244,991	$23,244,991
PENELEC	$1,675,853	$11,645,044	$13,320,897	$403,889	$11,993,445	$12,397,334
Pepco	$1,595,597	$8,301,363	$9,896,960	$0	$9,914,160	$9,914,160
PPL	$37,886	$24,416,798	$24,454,684	$90,643	$26,158,789	$26,249,432
PSEG	$37,255	$27,659,023	$27,696,277	$0	$28,164,482	$28,164,482
RECO	$1,239	$0	$1,239	$0	$0	$0
(Imp/Exp/Wheels)	$0	$19,435,328	$19,435,328	$0	$15,909,575	$15,909,575
Total	$20,379,379	$311,276,291	$331,655,670	$13,138,854	$328,829,532	$341,968,385

Frequency Response

On February 15, 2018, the Commission issued Order No. 842, which modified the pro forma large and small generator interconnection agreements and procedures to require newly interconnecting generating facilities, both synchronous and nonsynchronous, to include equipment for primary frequency response capability as a condition to receive interconnection service.[126] Such equipment must include a governor or equivalent controls with the capability of operating at a maximum 5 percent droop and ±0.036 Hz deadband (or the equivalent or better).

PJM filed revisions in compliance with Order No. 842 that substantively incorporated the pro forma agreements into its market rules.[127]

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

126 157 FERC ¶ 61,122 (2016).
127 See 164 FERC ¶ 61,224 (2018).

Frequency Control Definition

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

- **Inertial Response.** Inertial response to frequency excursion is the natural resistance of rotating mass turbine generators to change in their stored kinetic energy. This response is immediate and resists short term changes to ACE from the instant of the disturbance up to twenty seconds after the disturbance.
- **Primary Frequency Response.** Primary frequency response is a response to a disturbance based on a local detection of frequency and local operational control settings. Primary frequency response begins within a few seconds and extends up to a minute. The purpose of primary frequency response is to arrest and stabilize the system until other measures (secondary and tertiary frequency response) become active.
- **Secondary Frequency Control.** Secondary frequency control is called regulation. In PJM it begins taking effect within 10 to fifteen seconds and can maintain itself for several minutes up to an hour in some cases. It is controlled by PJM which detects the grid frequency, calculates a counterbalancing signal, and transmits that signal to all regulating resources.
- **Tertiary Frequency Control.** Tertiary frequency control and imbalance control lasting 10 minutes to an hour is available in PJM as Primary Reserve. It is initiated by an all call from the PJM control center.

Congestion and Marginal Losses

When there are binding transmission constraints and locational price differences, load pays more for energy than generation is paid to produce that energy. The difference is congestion.[1]

The locational marginal price (LMP) is the incremental price of energy at a bus. The LMP at a bus is the sum of three components: the system marginal price (SMP) or energy component, the congestion component (CLMP), and the marginal loss component (MLMP). SMP, MLMP and CLMP are products of the least cost, security constrained dispatch of system resources to meet system load.

SMP is the incremental price of energy for the system, given the current dispatch, at the load-weighted reference bus, or LMP net of losses and congestion. SMP is the LMP at the load-weighted reference bus. The load-weighted reference bus is not a fixed location but varies with the distribution of load at system load buses.

CLMP is the incremental price of congestion at each bus, based on the shadow prices associated with the relief of binding constraints in the security constrained optimization. CLMPs are positive or negative depending on location relative to binding constraints and relative to the load-weighted reference bus. In an unconstrained system CLMPs will be zero. The relative values of SMP and CLMP are arbitrary and depend on the load-weighted reference bus.

MLMP is the incremental price of losses at a bus, based on marginal loss factors in the security constrained optimization. Losses refer to energy lost to physical resistance in the transmission network as power is moved from generation to load.

Total losses refer to the total system-wide transmission losses as a result of moving power from injections to withdrawals on the system. Marginal losses are the incremental change in system losses caused by changes in load and generation.

Congestion is neither good nor bad, but is a direct measure of the extent to which there are multiple marginal generating units with different offers dispatched to serve load as a result of transmission constraints. Congestion occurs when available, least-cost energy cannot be delivered to all load because transmission facilities are not adequate to deliver that energy to one or more areas, and higher cost units in the constrained area(s) must be dispatched to meet the load.[2] The result is that the price of energy in the constrained area(s) is higher than in the unconstrained area. Load in the constrained area pays the higher price for all energy including energy from low cost and energy from high cost generation while generators are paid the price at their bus.

The energy, marginal losses and congestion metrics must be interpreted carefully. The term total congestion refers to what is actually net congestion, which is calculated as net implicit congestion costs plus net explicit congestion costs plus net inadvertent congestion charges. The net implicit congestion costs are the load congestion payments less generation congestion credits. This section refers to total energy costs and total marginal loss costs in the same way. As with congestion, total energy costs are more precisely termed net energy costs and total marginal loss costs are more precisely termed net marginal loss costs. Ignoring interchange, total generation MWh must be greater than total load MWh in any hour in order to provide for losses. Since the hourly integrated energy component of LMP is the same for every bus within every hour, the net energy bill is negative (ignoring net interchange), with more generation credits than load payments in every hour.[3]

This report provides two measures of local congestion: area based congestion and constraint based congestion. Total congestion is the same for both measures. Local congestion differs between the two measures.

Area based congestion is defined as the total congestion payments by load at the buses within a defined area, typically a zone, minus the total congestion credits received by generation at the buses in the same defined area.

Constraint based congestion is defined as the total congestion payments by load at the buses within a

1 The difference in losses is not part of congestion.

2 This is referred to as dispatching units out of economic merit order. Economic merit order is the order of all generator offers from lowest to highest cost. Congestion occurs when loadings on transmission facilities mean the next unit in merit order cannot be used and a higher cost unit must be used in its place. Dispatch within the constrained area follows merit order for the units available to relieve the constraint.

3 The total congestion and marginal losses for 2018 were calculated as of January 24, 2019, and are subject to change, based on continued PJM billing updates.

defined area minus total congestion credits received by all generation that supplied that load, given the transmission constraints, regardless of location in the PJM system.

The MMU has previously reported zonal area based congestion in the congestion appendix.[4] By including only generation credits received by generation within a defined area, area based congestion calculations ignore credits associated with generation outside of the defined area that may, based on unit offers and transmission system capability, be supplying a portion of the load in the area. Total area based congestion is the sum of all congestion for generators and load and virtuals with market activity at the buses in each zone in PJM.

Constraint based congestion reflects differences between credits and charges caused by binding transmission limits on power flow from generators, regardless of location, to load in a specific area. Total constraint based congestion is the sum of all congestion for generators and load and virtuals with market activity at the buses in each zone in PJM.

Constraint based congestion is a more accurate measure of local congestion, which is the difference between load charges and generation credits caused by transmission constraints that provide access to low cost generation and require the use of higher cost local generation. Constraint based congestion reflects the underlying characteristics of the complete power system as it affects the defined area, including the nature and capability of transmission facilities, the offers and geographic distribution of generation facilities, the level and geographic distribution of incremental bids and offers and the geographic and temporal distribution of load.

Overview

Congestion Cost

- **Total Congestion.** Total congestion costs increased by $612.3 million or 87.8 percent, from $697.6 million in 2017 to $1,309.9 million in 2018.
- **Day-Ahead Congestion.** Day-ahead congestion costs increased by $645.9 million or 88.1 percent, from $733.1 million in 2017 to $1,378.9 million in 2018.
- **Balancing Congestion.** Negative balancing congestion costs increased by $33.6 million or 94.6 percent, from -$35.5 million in 2017 to -$69.0 million in 2018. Negative balancing explicit costs increased by $8.1 million or 77.8 percent, from -$10.4 million in 2017 to -$18.5 million in 2018.
- **Real-Time Congestion.** Real-time congestion costs increased by $667.6 million or 81.7 percent, from $817.5 million in 2017 to $1,485.1 million in 2018.
- **Monthly Congestion.** Monthly total congestion costs in 2018 ranged from $45.2 million in February to $535.9 million in January.
- **Geographic Differences in CLMP.** Differences in CLMP among eastern, southern and western control zones in PJM were primarily a result of congestion on the AEP - DOM Interface, the Cloverdale Transformer, the Tanners Creek - Miami Fort Flowgate, the Graceton - Safe Harbor Line, and the 5004/5005 Interface.
- **Congestion Frequency.** Congestion frequency continued to be significantly higher in the Day-Ahead Energy Market than in the Real-Time Energy Market in 2018. The number of congestion event hours in the Day-Ahead Energy Market was about six times the number of congestion event hours in the Real-Time Energy Market.

  But day-ahead congestion frequency decreased by 55.9 percent from 300,923 congestion event hours in 2017 to 132,598 congestion event hours in 2018 as a result of a significant decrease in up to congestion transaction (UTC) activities in response to the February 20, 2018, FERC order that limited UTC trading, effective February 22, 2018, to hubs, residual metered load, and interfaces.[5]

  Real-time congestion frequency increased by 2.3 percent from 22,393 congestion event hours in 2017 to 22,910 congestion event hours in 2018.
- **Congested Facilities.** Day-ahead, congestion event hours decreased on all types of facilities as a result of a significant decrease in UTC activities caused by the February 20, 2018, FERC order.

  The AEP - DOM Interface was the largest contributor to congestion costs in 2018. With $121.0 million in

4 See the *2018 State of the Market Report for PJM*, Vol. 2, Appendix G "Congestion and Marginal Losses."

5 162 FERC ¶ 61,139.

total congestion costs, it accounted for 9.2 percent of the total PJM congestion costs in 2018.

- **CT Pricing Logic and Closed Loop Interface Related Congestion.** CT pricing logic and closed loop interfaces caused -$1.3 million of day-ahead congestion in 2018 and -$10.2 million of balancing congestion in 2018.
- **Zonal Congestion.** Using the constraint based measure, AEP had the largest zonal congestion costs among all control zones in 2018. AEP had $223.8 million in zonal congestion costs, comprised of $234.9 million in zonal day-ahead congestion costs and -$11.1 million in zonal balancing congestion costs. The AEP - DOM Interface, the Capitol Hill – Chemical Line, the Cloverdale Transformer, the Tanners Creek - Miami Fort Flowgate, and the Graceton - Safe Harbor Line contributed $71.4 million, or 31.9 percent of the local AEP control zone congestion costs.

Marginal Loss Cost

- **Total Marginal Loss Costs.** Total marginal loss costs increased by $269.3 million or 39.0 percent, from $690.8 million in 2017 to $960.1 million in 2018. The loss MWh in PJM increased by 700.3 GWh or 4.7 percent, from 14,920 GWh in 2017 to 15,620 GWh in 2018. The loss component of real-time LMP in 2018 was $0.02, compared to $0.01 in 2017.
- **Monthly Total Marginal Loss Costs.** Monthly total marginal loss costs in 2018 ranged from $49.5 million in February to $222.8 million in January.
- **Day-Ahead Marginal Loss Costs.** Day-ahead marginal loss costs increased by $227.3 million or 29.5 percent, from $769.9 million in 2017 to $997.2 million in 2018.
- **Balancing Marginal Loss Costs.** Negative balancing marginal loss costs decreased by $42.0 million or 53.1 percent, from -$79.1 million in 2017 to -$37.1 million in 2018.
- **Total Marginal Loss Surplus.** The total marginal loss surplus increased in 2018 by $105.6 million or 49.2 percent, from $214.6 million in 2017, to $320.2 million in 2018.

Energy Cost

- **Total Energy Costs.** Total energy costs decreased by $161.5 million or 34.0 percent, from -$475.2 million in 2017 to -$636.7 million in 2018.
- **Day-Ahead Energy Costs.** Day-ahead energy costs decreased by $62.5 million or 9.6 percent, from -$648.5 million in 2017 to -$711.0 million in 2018.
- **Balancing Energy Costs.** Balancing energy costs decreased by $96.5 million or 58.1 percent, from $166.2 million in 2017 to $69.7 million in 2018.
- **Monthly Total Energy Costs.** Monthly total energy costs in 2018 ranged from -$150.9 million in January to -$33.6 million in February.

Conclusion

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

Total congestion in 2018 increased significantly from 2017. The increase was a result of an increase in day-ahead congestion in January 2018 which was a result of high gas costs and associated LMPs in the early part of January 2018 and the use of high price oil fired units to control for contingencies caused by outages related to transmission upgrades in Virginia in May 2018.

Balancing explicit congestion decreased by $8.1 million or 77.8 percent, from -$10.4 million in 2017 to -$18.5 million in 2018. The decrease in balancing explicit congestion costs was the result of the decrease in balancing explicit costs incurred by up to congestion transactions (UTCs) in May and June of 2018. The balancing congestion costs were -$16.0 million and -$19.9 million in May and June. The large negative balancing congestion cost was caused in large part by UTCs profiting from day-ahead and real-time market modeling differences, including a number of constraints that were modeled in the real-time market but not modeled in the day-ahead market.

The monthly total congestion costs ranged from $45.2 million in February to $535.9 million in January, 2018.

The impact of UTCs on the frequency of day-ahead congestion was illustrated by the significant reduction in day-ahead congestion event hours following the decrease in up to congestion (UTC) transaction activities that resulted from the February 20, 2018, FERC order that limited UTC trading to hubs, residual metered load, and interfaces.

The current ARR/FTR design does not serve as an efficient way to ensure that load receives all the congestion revenues and has the ability to receive the auction revenues associated with rights to all the potential congestion revenues. Total ARR and self scheduled FTR revenue offset only 65.3, 90.3, 100.0, 50.0 and, if surplus through December 2018 were distributed, 74.2 percent of total congestion costs including congestion in the Day-Ahead Energy Market and the balancing energy market for the 2014/2015, 2015/2016, 2016/2017, 2017/2018 and the first seven months of 2018/2019 planning periods.

Issues

PJM uses closed loop interfaces and CT pricing logic to force otherwise uneconomic resources to be marginal and set price in the day-ahead or real-time market solution. PJM uses a closed loop interface or CT pricing logic to create an artificial constraint with a variable flow limit, paired with an artificial override of the inflexible resource's economic minimum, to make the resource marginal in PJM LMP security constraint pricing logic.

Through the assumption of artificial flexibility on the affected unit and artificially creating a constraint for which the otherwise inflexible resource can be marginal, PJM's use of both the closed loop interface and CT pricing logic forces the affected resource bus LMP to match the marginal offer of the resource. In the case of a closed loop interface, all buses within the interface are modeled as having a distribution factor (DFAX) of 1.0 to the constraint and therefore have the same constraint related congestion component of price at the marginal resource's bus. In the CT pricing logic case, the constraint affects the CLMP of downstream (constrained side) buses in proportion to their DFAX to that constraint.[6] The objective of making inflexible resources marginal is to minimize the uplift costs associated with the inflexible resources that PJM commits for system security reasons.

The use of closed loop interfaces and CT pricing logic can be a source of modeling differences between the day-ahead and real-time market. If closed loop interfaces and CT pricing logic are not included in the day-ahead market in exactly the same way as in the real-time market, including specific constraints and limits, the differences between the day-ahead and real-time market model will result in positive or negative balancing congestion.

The use of the closed loop interface and CT pricing logic makes the inflexible resource marginal in the real-time market. Failure to model the same constraint in the day-ahead market will result in pricing and congestion settlement differences between the day-ahead and real-time market. Any modeling differences create false arbitrage opportunities for virtual bids and contribute to negative balancing congestion. PJM attempts to incorporate its real-time use of closed loop interfaces and CT pricing logic in the day-ahead market, although the matching is necessarily imperfect and with a lag.

Use of closed loop interfaces and CT price setting logic requires the manipulation of the economic dispatch model. Closed loop interfaces and CT price setting logic force higher cost inflexible units to be marginal. The resulting constraint specific positive shadow price means a higher price at the unit's bus and at other affected locations.

The result is that more power is produced than consumed in the artificial closed loop. The rest of the system receives power from the closed loop, generators are backed down and prices are lower.

The result is that PJM pays out more to generators in the closed loop than it collects from load. The result of using closed loops and CT price setting logic is negative congestion.

6 The constrained side means the higher priced side with a positive CLMP created by the constraint.

Locational Marginal Price (LMP)

Components

On June 1, 2007, PJM changed from a single node reference bus to a distributed load reference bus. While the use of a single node reference bus or a distributed load reference bus has no effect on the total LMP, the use of a single node reference bus or a distributed load reference bus will affect the components of LMP. With a distributed load reference bus, the energy component is a load-weighted system price. There is no congestion or losses included in the load-weighted reference bus price, unlike the case with a single node reference bus.

LMP at a bus reflects the incremental price of energy at that bus. LMP at any bus is the sum of three components: the system marginal price (SMP), marginal loss component of LMP (MLMP), and congestion component of LMP (CLMP).

SMP, MLMP and CLMP are a product of the least cost, security constrained dispatch of system resources to meet system load. SMP is the incremental cost of energy, given the current dispatch and given the choice of reference bus. SMP is LMP net of losses and congestion. Losses refer to energy lost to physical resistance in the transmission and distribution network as power is moved from generation to load. The greater the resistance of the system to flows of energy from generation to loads, the greater the losses of the system and the greater the proportion of energy needed to meet a given level of load. Marginal losses are the incremental change in system power losses caused by changes in the system load and generation patterns.[7] The first derivative of total losses with respect to the power flow equals marginal losses. Congestion cost reflects the incremental cost of relieving transmission constraints while maintaining system power balance. Congestion occurs when available, least-cost energy cannot be delivered to all loads because transmission facilities are not adequate to deliver that energy. When the least-cost available energy cannot be delivered to load in a transmission constrained area, higher cost units in the constrained area must be dispatched to meet that load.[8] The result is that the price of energy in the constrained area is higher than in the unconstrained area because of the combination of transmission limitations and the cost of local generation. Load in the constrained area pays the higher price for all energy including energy from low cost generation and energy from high cost generation. Congestion is the difference between the total cost of energy paid by load in the transmission constrained area and the total revenue received by generation in the transmission constrained area, net of losses. Congestion equals the sum of day-ahead and balancing congestion.

Table 11-1 shows the PJM real-time, load-weighted average LMP components for 2008 through 2018.[9]

The load-weighted average real-time LMP increased $7.25 or 23.4 percent from $30.99 in 2017 to $38.24 in 2018. The load-weighted, average congestion component increased by $0.02 from $0.02 in 2017 to $0.04 in 2018. The load-weighted average loss component in 2018 was $0.02 compared to $0.01 in 2017. The load-weighted, average energy component increased by $7.23 or 23.4 percent from $30.96 in 2017 to $38.19 in 2018.

Table 11-1 PJM real-time, load-weighted average LMP components (Dollars per MWh): 2008 through 2018[10]

	Real-Time LMP	Energy Component	Congestion Component	Loss Component
2008	$71.13	$71.02	$0.06	$0.05
2009	$39.05	$38.97	$0.05	$0.03
2010	$48.35	$48.23	$0.08	$0.04
2011	$45.94	$45.87	$0.05	$0.02
2012	$35.23	$35.18	$0.04	$0.01
2013	$38.66	$38.64	$0.01	$0.02
2014	$53.14	$53.13	($0.02)	$0.02
2015	$36.16	$36.11	$0.04	$0.02
2016	$29.23	$29.18	$0.04	$0.01
2017	$30.99	$30.96	$0.02	$0.01
2018	$38.24	$38.19	$0.04	$0.02

7 For additional information, see the *MMU Technical Reference for PJM Markets*, at "Marginal Losses," <http://www.monitoringanalytics.com/reports/Technical_References/docs/2010-som-pjm-technical-reference.pdf>.

8 This is referred to as dispatching units out of economic merit order. Economic merit order is the order of all generator offers from lowest to highest cost. Congestion occurs when loadings on transmission facilities mean the next unit in merit order cannot be used and a higher cost unit must be used in its place.

9 The PJM real-time, load-weighted price is weighted by accounting load, which differs from the state-estimated load used in determination of the energy component (SMP). In the Real-Time Energy Market, the distributed load reference bus is weighted by state-estimated load in real time. When the LMP is calculated in real time, the energy component equals the system load-weighted price. But real-time bus-specific loads are adjusted, after the fact, based on updated load information from meters. This meter adjusted load is accounting load that is used in settlements and is used to calculate reported PJM load-weighted prices. This after the fact adjustment means that the Real-Time Energy Market energy component of LMP (SMP) and the PJM real-time, load-weighted LMP are not equal. The difference between the real-time energy component of LMP and the PJM-wide real-time, load-weighted LMP is a result of the difference between state-estimated and metered loads used to weight the load-weighted reference bus and the load-weighted LMP. Without these adjustments, the congestion component of system average LMP would be zero.

10 Calculated values shown in Section 11, "Congestion and Marginal Losses," are based on unrounded, underlying data and may differ from calculations based on the rounded values in the tables.

Table 11-2 shows the PJM day-ahead, load-weighted average LMP components for 2008 through 2018.[11] The load-weighted average day-ahead LMP increased $7.13, or 23.1 percent, from $30.85 in 2017 to $37.97 in 2018. The load-weighted, average congestion component increased $0.11 from $0.05 in 2017 to $0.16 in 2018. The load-weighted, average loss component increased from -$0.02 in 2017 to -$0.01 in 2018. The load-weighted average energy component increased $7.02, or 22.8 percent, from $30.81 in 2017 to $37.83 in 2018.

Table 11-2 PJM day-ahead, load-weighted average LMP components (Dollars per MWh): 2008 through 2018

	Day-Ahead LMP	Energy Component	Congestion Component	Loss Component
2008	$70.25	$70.56	($0.08)	($0.22)
2009	$38.82	$38.96	($0.04)	($0.09)
2010	$47.65	$47.67	$0.05	($0.07)
2011	$45.19	$45.40	($0.06)	($0.15)
2012	$34.55	$34.46	$0.11	($0.01)
2013	$38.93	$38.79	$0.13	$0.00
2014	$53.62	$53.38	$0.26	($0.02)
2015	$36.73	$36.51	$0.24	($0.01)
2016	$29.68	$29.55	$0.14	($0.01)
2017	$30.85	$30.81	$0.05	($0.02)
2018	$37.97	$37.83	$0.16	($0.01)

Table 11-3 shows the PJM real-time, load-weighted average LMP by constrained and unconstrained hours. In 2018, January had the highest real-time, load-weighted average LMP as a result of cold weather and high gas prices in early January 2018.

Table 11-3 PJM real-time, load-weighted average LMP by constrained and unconstrained hours (Dollars per MWh): 2017 and 2018

	2017		2018	
	Constrained Hours	Unconstrained Hours	Constrained Hours	Unconstrained Hours
Jan	$32.96	$26.37	$96.69	$24.03
Feb	$25.82	$24.26	$27.00	$23.93
Mar	$32.56	$26.54	$33.35	$23.64
Apr	$29.26	$23.90	$35.74	$24.92
May	$32.27	$23.90	$38.78	$17.24
Jun	$29.23	$18.80	$34.55	$21.81
Jul	$34.22	$26.33	$37.08	$26.09
Aug	$28.39	$24.66	$38.64	$25.11
Sep	$33.79	$21.28	$36.83	$26.29
Oct	$28.69	$29.20	$35.27	$26.11
Nov	$29.43	$23.26	$37.64	$26.58
Dec	$44.60	$24.74	$34.60	$24.19
Avg	$31.81	$24.42	$41.15	$24.71

Zonal Components

The real-time components of LMP for each control zone are presented in Table 11-4 for 2017 and 2018. In 2018, BGE had the highest real-time congestion component of all control zones, $3.82, and ComEd had the lowest real-time congestion component, -$5.53.

11 In the Real-Time Energy Market, the energy component (SMP) equals the system load-weighted price, with the caveat about state-estimated versus metered load. However, in the Day-Ahead Energy Market the day-ahead energy component of LMP (SMP) and the PJM day-ahead, load-weighted LMP are not equal. The difference between the day-ahead energy component of LMP and the PJM day-ahead, load-weighted LMP is a result of the difference in the types of load used to weight the load-weighted reference bus and the load-weighted LMP. In the Day-Ahead Energy Market, the distributed load reference bus is weighted by fixed-demand bids only and the day-ahead SMP is, therefore, a system fixed demand weighted price. The day-ahead, load-weighted LMP calculation uses all types of demand, including fixed, price-sensitive and decrement bids.

Table 11-4 Zonal and PJM real-time, load-weighted average LMP components (Dollars per MWh): 2017 and 2018

	2017				2018			
	Real-Time LMP	Energy Component	Congestion Component	Loss Component	Real-Time LMP	Energy Component	Congestion Component	Loss Component
AECO	$29.63	$31.03	($1.86)	$0.46	$37.10	$37.72	($1.45)	$0.83
AEP	$30.17	$30.78	($0.31)	($0.31)	$37.84	$38.20	$0.08	($0.44)
APS	$31.32	$30.92	$0.34	$0.06	$39.83	$38.45	$1.12	$0.25
ATSI	$31.23	$30.70	$0.01	$0.52	$40.24	$37.64	$2.00	$0.60
BGE	$34.76	$31.28	$2.43	$1.06	$44.09	$38.91	$3.82	$1.36
ComEd	$28.29	$30.82	($1.35)	($1.19)	$30.08	$37.45	($5.53)	($1.84)
DAY	$31.06	$30.87	($0.27)	$0.46	$39.00	$38.16	$0.17	$0.67
DEOK	$30.55	$30.91	$0.40	($0.77)	$39.20	$38.14	$1.99	($0.93)
DLCO	$30.63	$30.82	($0.04)	($0.15)	$40.03	$37.72	$2.17	$0.14
Dominion	$33.49	$31.21	$1.90	$0.38	$43.22	$39.09	$3.62	$0.52
DPL	$33.39	$31.35	$1.15	$0.89	$43.82	$39.12	$3.16	$1.54
EKPC	$29.19	$31.34	($1.32)	($0.82)	$36.24	$39.76	($2.31)	($1.21)
JCPL	$30.74	$31.30	($0.94)	$0.38	$37.11	$38.12	($1.66)	$0.65
Met-Ed	$31.15	$30.97	($0.07)	$0.25	$37.10	$38.14	($1.37)	$0.33
OVEC	NA	NA	NA	NA	$30.61	$31.82	($0.27)	($0.94)
PECO	$29.80	$31.04	($1.38)	$0.14	$36.40	$38.15	($2.12)	$0.37
PENELEC	$30.48	$30.60	($0.33)	$0.22	$37.95	$37.74	($0.19)	$0.40
Pepco	$33.70	$31.19	$1.82	$0.69	$42.65	$38.76	$2.98	$0.91
PPL	$29.99	$30.96	($0.99)	$0.02	$35.99	$38.38	($2.37)	($0.02)
PSEG	$30.92	$30.91	($0.37)	$0.38	$36.72	$37.61	($1.48)	$0.59
RECO	$31.26	$31.28	($0.43)	$0.41	$37.43	$37.85	($0.97)	$0.56
PJM	$30.99	$30.96	$0.02	$0.01	$38.24	$38.19	$0.04	$0.02

The day-ahead components of LMP for each control zone are presented in Table 11-5 for 2017 and 2018. In 2018, BGE had the highest day-ahead congestion component of all control zones, $4.23, and ComEd had the lowest day-ahead congestion component, -$5.41.

Table 11-5 Zonal and PJM day-ahead, load-weighted average LMP components (Dollars per MWh): 2017 and 2018

	2017				2018			
	Day-Ahead LMP	Energy Component	Congestion Component	Loss Component	Day-Ahead LMP	Energy Component	Congestion Component	Loss Component
AECO	$29.14	$30.94	($1.98)	$0.18	$36.74	$37.55	($1.32)	$0.51
AEP	$30.56	$30.75	$0.05	($0.24)	$37.49	$37.90	($0.04)	($0.37)
APS	$31.17	$30.75	$0.42	($0.00)	$39.18	$37.85	$1.12	$0.21
ATSI	$31.23	$30.62	$0.22	$0.39	$39.06	$37.34	$1.18	$0.54
BGE	$34.78	$31.14	$2.72	$0.92	$43.83	$38.41	$4.23	$1.20
ComEd	$28.24	$30.67	($1.59)	($0.84)	$30.15	$37.15	($5.41)	($1.58)
DAY	$31.37	$30.82	$0.01	$0.54	$38.89	$37.79	$0.35	$0.75
DEOK	$31.00	$30.86	$0.66	($0.52)	$40.14	$37.75	$2.97	($0.58)
DLCO	$30.76	$30.74	$0.23	($0.21)	$39.14	$37.48	$1.51	$0.15
Dominion	$33.59	$31.14	$2.04	$0.42	$43.34	$38.73	$4.04	$0.57
DPL	$32.18	$31.22	$0.45	$0.52	$42.53	$38.77	$2.63	$1.12
EKPC	$29.95	$31.32	($0.63)	($0.73)	$36.04	$39.42	($2.29)	($1.09)
JCPL	$29.92	$31.06	($1.29)	$0.15	$36.67	$37.77	($1.47)	$0.37
Met-Ed	$30.44	$30.80	($0.34)	($0.03)	$36.81	$37.65	($0.81)	($0.03)
OVEC	NA	NA	NA	NA	$0.00	$0.00	$0.00	$0.00
PECO	$28.97	$30.76	($1.71)	($0.08)	$35.98	$37.68	($1.76)	$0.06
PENELEC	$29.98	$30.61	($0.65)	$0.02	$37.61	$37.78	($0.42)	$0.25
Pepco	$33.71	$30.95	$2.11	$0.64	$42.65	$38.39	$3.36	$0.91
PPL	$29.30	$30.74	($1.17)	($0.26)	$35.71	$37.82	($1.74)	($0.37)
PSEG	$30.47	$30.86	($0.62)	$0.23	$37.08	$37.59	($0.92)	$0.40
RECO	$30.66	$31.07	($0.66)	$0.25	$37.38	$37.72	($0.72)	$0.38
PJM	$30.85	$30.81	$0.05	($0.02)	$37.97	$37.83	$0.16	($0.01)

Hub Components

The real-time components of LMP for each hub are presented in Table 11-6 for 2017 and 2018.[12]

Table 11-6 Hub real-time, average LMP components (Dollars per MWh): 2017 and 2018

	2017				2018			
	Real-Time LMP	Energy Component	Congestion Component	Loss Component	Real-Time LMP	Energy Component	Congestion Component	Loss Component
AEP Gen Hub	$27.92	$29.39	($0.38)	($1.09)	$33.06	$35.69	($1.26)	($1.37)
AEP-DAY Hub	$28.81	$29.39	($0.19)	($0.38)	$34.48	$35.69	($0.67)	($0.55)
ATSI Gen Hub	$29.29	$29.39	($0.10)	$0.01	$36.61	$35.69	$1.00	($0.09)
Chicago Gen Hub	$26.31	$29.39	($1.59)	($1.49)	$28.16	$35.69	($5.35)	($2.18)
Chicago Hub	$26.97	$29.39	($1.34)	($1.08)	$28.68	$35.69	($5.33)	($1.68)
Dominion Hub	$31.12	$29.39	$1.55	$0.17	$38.89	$35.69	$3.00	$0.19
Eastern Hub	$30.75	$29.39	$0.65	$0.71	$38.47	$35.69	$1.62	$1.16
N Illinois Hub	$26.69	$29.39	($1.47)	($1.23)	$28.48	$35.69	($5.35)	($1.86)
New Jersey Hub	$28.64	$29.39	($1.02)	$0.27	$34.44	$35.69	($1.74)	$0.49
Ohio Hub	$28.89	$29.39	($0.17)	($0.34)	$34.32	$35.69	($0.82)	($0.55)
West Interface Hub	$29.77	$29.39	$0.57	($0.19)	$37.62	$35.69	$2.20	($0.27)
Western Hub	$29.82	$29.39	$0.37	$0.06	$36.57	$35.69	$0.74	$0.13

The day-ahead components of LMP for each hub are presented in Table 11-7 for 2017 and 2018.

Table 11-7 Hub day-ahead, average LMP components (Dollars per MWh): 2017 and 2018

	2017				2018			
	Day-Ahead LMP	Energy Component	Congestion Component	Loss Component	Day-Ahead LMP	Energy Component	Congestion Component	Loss Component
AEP Gen Hub	$28.36	$29.46	($0.10)	($1.00)	$33.28	$35.57	($1.05)	($1.24)
AEP-DAY Hub	$29.22	$29.46	$0.10	($0.34)	$34.63	$35.57	($0.47)	($0.47)
ATSI Gen Hub	$29.49	$29.46	$0.10	($0.07)	$36.04	$35.57	$0.54	($0.07)
Chicago Gen Hub	$26.33	$29.46	($1.94)	($1.18)	$28.21	$35.57	($5.41)	($1.95)
Chicago Hub	$27.07	$29.46	($1.65)	($0.74)	$28.77	$35.57	($5.38)	($1.43)
Dominion Hub	$31.36	$29.46	$1.68	$0.22	$39.04	$35.57	$3.18	$0.29
Eastern Hub	$30.25	$29.46	$0.34	$0.45	$38.04	$35.57	$1.54	$0.92
N Illinois Hub	$26.82	$29.46	($1.71)	($0.93)	$28.54	$35.57	($5.38)	($1.65)
New Jersey Hub	$28.46	$29.46	($1.11)	$0.12	$34.63	$35.57	($1.24)	$0.30
Ohio Hub	$29.26	$29.46	$0.10	($0.30)	$34.51	$35.57	($0.59)	($0.48)
West Interface Hub	$30.06	$29.46	$0.81	($0.21)	$37.33	$35.57	$1.99	($0.23)
Western Hub	$29.73	$29.46	$0.40	($0.13)	$36.45	$35.57	$0.79	$0.08

Congestion

Congestion Accounting

Total congestion costs equal net congestion costs plus explicit congestion costs. Net congestion costs equal load congestion payments minus generation congestion credits. Explicit congestion costs are the net congestion costs associated with point to point energy transactions. Each of these categories of congestion costs is comprised of day-ahead and balancing congestion costs. Congestion occurs in the Day-Ahead and Real-Time Energy Markets.[13] Day-ahead congestion costs are based on day-ahead MWh while balancing congestion costs are based on deviations between day-ahead and real-time MWh priced at the congestion price in the Real-Time Energy Market.

Prior to April 1, 2018, implicit balancing congestion costs calculated at the zonal and aggregate level were determined by bus specific deviations between day ahead and real time MWh priced at the bus specific congestion price in the Real-Time Energy Market. As of April 1, 2018, with the introduction of five minute settlement, implicit zonal and aggregate balancing congestion costs are determined by netting the bus specific hourly deviations across every bus in a zone or aggregate and pricing the resulting deviation in zone or aggregate total deviations at the zonal

12 The real-time components of LMP are the simple average of the hourly components for each hub. Some hubs include only generation buses and do not include load buses. The real-time components of LMP were previously reported as the real-time load-weighted average of the hourly components of LMP.

13 When the term *congestion charge* is used in documents by PJM's Market Settlement Operations, it has the same meaning as the term *congestion costs* as used here.

or aggregate congestion price in the Real-Time Energy Market.

Total congestion costs are equal to the net implicit congestion bill plus net explicit congestion costs plus net inadvertent congestion charges, incurred in both the Day-Ahead Energy Market and the balancing energy market.

Total congestion costs equal load congestion payments netted against generation congestion credits on an hourly basis, by billing organization, and summed for the given period.

Load congestion payments and generation congestion credits are calculated for both the Day-Ahead and balancing energy markets.

- **Day-Ahead Load Congestion Payments.** Day-ahead load congestion payments are calculated for all cleared demand, decrement bids and day-ahead energy market sale transactions. Day-ahead load congestion payments are calculated using MW and the load bus CLMP, the decrement bid CLMP or the CLMP at the source of the sale transaction, as applicable.
- **Day-Ahead Generation Congestion Credits.** Day-ahead generation congestion credits are calculated for all cleared generation, increment offers and day-ahead energy market purchase transactions. Day-ahead generation congestion credits are calculated using MW and the generator bus CLMP, the increment offer's CLMP or the CLMP at the sink of the purchase transaction, as applicable.
- **Balancing Load Congestion Payments.** Balancing load congestion payments are calculated for all deviations between a PJM member's real-time load and energy sale transactions and their day-ahead cleared demand, decrement bids and energy sale transactions. Balancing load congestion payments are calculated using MW deviations and the real-time CLMP for each bus where a deviation exists.
- **Balancing Generation Congestion Credits.** Balancing generation congestion credits are calculated for all deviations between a PJM member's real-time generation and energy purchase transactions and the day-ahead cleared generation, increment offers and energy purchase transactions. Balancing generation congestion credits are calculated using MW deviations and the real-time CLMP for each bus where a deviation exists.
- **Explicit Congestion Costs.** Explicit congestion costs are the net congestion costs associated with point to point energy transactions. These costs equal the product of the transacted MW and CLMP differences between sources (origins) and sinks (destinations) in the Day-Ahead Energy Market. Balancing energy market explicit congestion costs equal the product of the deviations between the real-time and day-ahead transacted MW and the differences between the real-time CLMP at the transactions' sources and sinks. Explicit congestion costs are calculated for internal purchase, import and export transaction, and up to congestion transactions (UTCs.)
- **Inadvertent Congestion Charges.** Inadvertent congestion charges are congestion charges resulting from the differences between the net actual energy flow and the net scheduled energy flow into or out of the PJM control area each hour. This inadvertent interchange of energy may be positive or negative, where positive interchange typically results in a charge while negative interchange typically results in a credit. Inadvertent congestion charges are common costs, not directly attributable to specific participants that are distributed on a load ratio basis.[14]

The congestion costs associated with specific constraints are the sum of the total day-ahead and balancing congestion costs associated with those constraints. The congestion costs in each zone are the sum of the congestion costs associated with each constraint that affects prices in the zone. The network nature of the transmission system means that congestion costs in a zone are frequently the result of constrained facilities located outside that zone.

Congestion costs can be both positive and negative and consequently load payments and generation credits can be both positive and negative. Total congestion costs, when positive, measure the total congestion payment by a participant group and when negative, measure the total congestion credit paid to a participant group. Load congestion payments, when positive, measure the total congestion payment by load and when negative,

14 PJM Operating Agreement Schedule 1 §3.7.

measure the total congestion credit paid by load. Generation congestion credits, when negative, measure the total congestion payment by generation and when positive, measure the total congestion credit paid to generation. Explicit congestion costs, when positive, measure the congestion payment by a PJM member and when negative, measure the congestion credit paid to a PJM member. Explicit congestion costs are calculated for up to congestion transactions (UTCs).

The accounting definitions can be misleading. Load pays for congestion. Generation does not pay for congestion. Some generation receives a price lower than SMP and some generation receives a price greater than SMP but that does not mean that generation is paying for congestion.

The CLMP is calculated with respect to the LMP at the system reference bus, also called the system marginal price (SMP). When a transmission constraint occurs, the resulting CLMP is positive on one side of the constraint and negative on the other side of the constraint and the corresponding congestion costs are positive or negative. For each transmission constraint, the CLMP reflects the cost of a constraint at a pricing node and is equal to the product of the constraint shadow price and the distribution factor at the pricing node. The total CLMP at a pricing node is the sum of all constraint contributions to LMP and is equal to the difference between the actual LMP that results from transmission constraints, excluding losses, and the SMP. If an area experiences lower prices because of a constraint, the CLMP in that area is negative.[15]

Total Congestion

Total congestion costs in PJM in 2018 were $1,309.9 million, which were comprised of load congestion payments of $360.8 million, generation credits of -$986.5 million and explicit congestion of -$37.4 million. Total congestion is the difference between what load pays for energy and what generation is paid for energy.

Table 11-8 shows total congestion for 2008 through 2018. Total congestion costs in Table 11-8 include congestion costs associated with PJM facilities and those associated with reciprocal, coordinated flowgates in MISO and in NYISO.[16 17]

Table 11-8 Total PJM congestion component costs (Dollars (Millions)): 2008 through 2018

	Congestion Costs (Millions)			
	Congestion Cost	Percent Change	Total PJM Billing	Percent of PJM Billing
2008	$2,052	NA	$34,306	6.0%
2009	$719	(65.0%)	$26,550	2.7%
2010	$1,423	98.0%	$34,771	4.1%
2011	$999	(29.8%)	$35,887	2.8%
2012	$529	(47.0%)	$29,181	1.8%
2013	$677	28.0%	$33,860	2.0%
2014	$1,932	185.5%	$50,030	3.9%
2015	$1,385	(28.3%)	$42,630	3.2%
2016	$1,024	(26.1%)	$39,050	2.6%
2017	$698	(31.9%)	$40,170	1.7%
2018	$1,310	87.8%	$49,790	2.6%

Table 11-9 shows total congestion by day-ahead and balancing component for 2008 through 2018. Table 11-10 and Table 11-11 show that the decrease in balancing explicit costs was the result of the decrease in balancing explicit costs incurred by up to congestion transactions (UTCs) in May and June of 2018. The market results were also affected by modelling differences between the day-ahead and real-time market models and large CLMP differences resulting from high gas prices from January 5, 2018, through January 8, 2018, and from the use of high price oil fired units to control for contingencies caused by outages related to transmission upgrades in Virginia in May 2018.

15 For an example of the congestion accounting methods used in this section, see *MMU Technical Reference for PJM Markets*, at "FTRs and ARRs," <http://www.monitoringanalytics.com/reports/Technical_References/docs/2010-som-pjm-technical-reference.pdf>.

16 See "Joint Operating Agreement Between the Midwest Independent Transmission System Operator, Inc. and PJM Interconnection, L.L.C.," (December 11, 2008) Section 6.1, Effective Date: May 30, 2016. <http://www.pjm.com/documents/agreements.aspx>.

17 See "NYISO Tariffs New York Independent System Operator, Inc.," (June 21, 2017) 35.12.1, Effective Date: May 1, 2017. <http://www.pjm.com/documents/agreements.aspx>.

Table 11-9 Total PJM congestion costs by accounting category by market (Dollars (Millions)): 2008 through 2018

	Congestion Costs (Millions)									
	Day-Ahead				Balancing					
	Load Payments	Generation Credits	Explicit Costs	Total	Load Payments	Generation Credits	Explicit Costs	Total	Inadvertent Charges	Grand Total
2008	$1,260.3	($1,133.1)	$203.0	$2,596.5	($225.9)	$79.2	($239.5)	($544.6)	$0.0	$2,051.8
2009	$292.3	($525.2)	$83.9	$901.4	($39.0)	$10.1	($133.4)	($182.4)	$0.0	$719.0
2010	$376.4	($1,239.8)	$96.9	$1,713.1	($37.5)	$72.8	($179.5)	($289.8)	($0.0)	$1,423.3
2011	$400.5	($777.6)	$66.9	$1,245.0	$53.5	$109.5	($190.0)	($246.0)	$0.0	$999.0
2012	$122.7	($525.3)	$131.9	$779.9	($7.6)	$57.9	($185.4)	($250.9)	$0.0	$529.0
2013	$281.2	($592.5)	$137.6	$1,011.3	$5.9	$131.3	($209.0)	($334.4)	$0.0	$676.9
2014	$595.5	($1,671.2)	($35.4)	$2,231.3	$52.7	$218.1	($133.6)	($299.1)	$0.0	$1,932.2
2015	$614.2	($967.6)	$50.3	$1,632.1	$0.6	$69.8	($177.6)	($246.9)	$0.0	$1,385.3
2016	$405.3	($654.1)	$41.0	$1,100.4	($4.5)	$28.4	($43.9)	($76.8)	($0.0)	$1,023.7
2017	$187.6	($554.1)	($8.6)	$733.1	$22.2	$47.2	($10.4)	($35.5)	$0.0	$697.6
2018	$349.3	($1,048.6)	($18.9)	$1,378.9	$11.5	$62.0	($18.5)	($69.0)	$0.0	$1,309.9

Table 11-10 and Table 11-11 show the total congestion costs for each transaction type in 2018 and 2017. Table 11-10 shows that in 2018 DECs paid $25.3 million in congestion costs in the day-ahead market, were paid $32.7 million in congestion credits in the balancing energy market, resulting in a net payment of $7.4 million in total congestion credits. In 2018, INCs paid $20.5 million in congestion charges in the day-ahead market, were paid $30.0 million in congestion credits in the balancing energy market resulting in a net payment of $9.5 million in total congestion credits. In 2018, up to congestion (UTCs) were paid $19.4 million in congestion credits in the day-ahead market, were paid $7.9 million in congestion credits in the balancing market resulting in a total payment of $27.4 million in total congestion credits.

Table 11-10 Total PJM congestion costs by transaction type by market (Dollars (Millions)): 2018

	Congestion Costs (Millions)									
	Day-Ahead				Balancing					
Transaction Type	Load Payments	Generation Credits	Explicit Costs	Total	Load Payments	Generation Credits	Explicit Costs	Total	Inadvertent Charges	Grand Total
DEC	$25.3	$0.0	$0.0	$25.3	($32.7)	$0.0	$0.0	($32.7)	$0.0	($7.4)
Demand	$101.0	$0.0	$0.0	$101.0	$56.3	$0.0	$0.0	$56.3	$0.0	$157.3
Demand Response	($0.0)	$0.0	$0.0	($0.0)	$0.0	$0.0	$0.0	$0.0	$0.0	($0.0)
Explicit Congestion Only	$0.0	$0.0	$2.2	$2.2	$0.0	$0.0	($0.8)	($0.8)	$0.0	$1.4
Explicit Congestion and Loss Only	$0.0	$0.0	($0.1)	($0.1)	$0.0	$0.0	($0.0)	($0.0)	$0.0	($0.2)
Export	($59.9)	$0.0	($1.0)	($60.9)	($14.7)	$0.0	($5.8)	($20.5)	$0.0	($81.5)
Generation	$0.0	($1,304.8)	$0.0	$1,304.8	$0.0	$70.9	$0.0	($70.9)	$0.0	$1,233.9
Grandfathered Overuse	$0.0	$0.0	($0.6)	($0.6)	$0.0	$0.0	$0.0	$0.0	$0.0	($0.5)
Import	$0.0	($6.2)	$0.0	$6.2	$0.0	($41.5)	($3.5)	$38.0	$0.0	$44.2
INC	$0.0	($20.5)	$0.0	$20.5	$0.0	$30.0	$0.0	($30.0)	$0.0	($9.5)
Internal Bilateral	$282.8	$282.8	$0.0	($0.0)	$3.4	$3.4	$0.0	($0.0)	$0.0	($0.0)
Up to Congestion	$0.0	$0.0	($19.4)	($19.4)	$0.0	$0.0	($7.9)	($7.9)	$0.0	($27.4)
Wheel In	$0.0	$0.0	$0.0	$0.0	$0.0	($0.8)	($0.5)	$0.3	$0.0	$0.3
Wheel Out	$0.0	$0.0	$0.0	$0.0	($0.8)	$0.0	$0.0	($0.8)	$0.0	($0.8)
Total	$349.3	($1,048.6)	($18.9)	$1,378.9	$11.5	$62.0	($18.5)	($69.0)	$0.0	$1,309.9

Table 11-11 Total PJM congestion costs by transaction type by market (Dollars (Millions)): 2017

	Congestion Costs (Millions)									
	Day-Ahead				Balancing					
Transaction Type	Load Payments	Generation Credits	Explicit Costs	Total	Load Payments	Generation Credits	Explicit Costs	Total	Inadvertent Charges	Grand Total
DEC	$4.3	$0.0	$0.0	**$4.3**	($17.1)	$0.0	$0.0	($17.1)	$0.0	($12.8)
Demand	$35.7	$0.0	$0.0	**$35.7**	$40.2	$0.0	$0.0	$40.2	$0.0	$75.9
Demand Response	($0.0)	$0.0	$0.0	**($0.0)**	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Explicit Congestion Only	$0.0	$0.0	$1.0	**$1.0**	$0.0	$0.0	$0.0	$0.0	$0.0	$1.0
Export	($29.7)	$0.0	($0.5)	**($30.3)**	($4.4)	$0.0	$1.8	($2.6)	$0.0	($32.9)
Generation	$0.0	($739.9)	$0.0	**$739.9**	$0.0	$53.5	$0.0	($53.5)	$0.0	$686.3
Grandfathered Overuse	$0.0	$0.0	($0.1)	**($0.1)**	$0.0	$0.0	($0.4)	($0.4)	$0.0	($0.5)
Import	$0.0	($1.7)	$0.0	**$1.7**	$0.0	($9.5)	($0.9)	$8.7	$0.0	$10.4
INC	$0.0	$10.3	$0.0	**($10.3)**	$0.0	($0.2)	$0.0	$0.2	$0.0	($10.2)
Internal Bilateral	$177.4	$177.3	($0.1)	**($0.0)**	$3.6	$3.6	($0.0)	($0.0)	$0.0	($0.0)
Up to Congestion	$0.0	$0.0	($8.9)	**($8.9)**	$0.0	$0.0	($10.8)	($10.8)	$0.0	($19.7)
Wheel In	$0.0	($0.1)	$0.1	**$0.2**	$0.0	($0.2)	($0.1)	$0.1	$0.0	$0.3
Wheel Out	($0.1)	$0.0	$0.0	**($0.1)**	($0.2)	$0.0	$0.0	($0.2)	$0.0	($0.4)
Total	$187.6	($554.1)	($8.6)	**$733.1**	$22.2	$47.2	($10.4)	($35.5)	$0.0	$697.6

Table 11-12 shows the change in total congestion cost incurred by transaction type from 2017 to 2018. Total congestion cost incurred by generation increased by $547.6 million, and total congestion cost incurred by demand increased by $81.4 million. The total congestion payments to up to congestion transactions (UTCs) increased by $7.6 million, from $19.7 million in 2017 to $27.4 million in 2018. Total day-ahead congestion costs payments to UTCs increased by $10.5 million from $8.9 million in 2017 to $19.4 million in 2018. Over the same period balancing congestion costs payments to UTCs decreased by $2.9 million, from $10.8 million in 2017 to $7.9 million in 2018.

Table 11-12 Change in total PJM congestion costs by transaction type by market: 2017 to 2018 (Dollars (Millions))

	Change in Congestion Costs (Millions)									
	Day-Ahead				Balancing					
Transaction Type	Load Payments	Generation Credits	Explicit Costs	Total	Load Payments	Generation Credits	Explicit Costs	Total	Inadvertent Charges	Grand Total
DEC	$21.0	$0.0	$0.0	$21.0	($15.6)	$0.0	$0.0	($15.6)	$0.0	$5.4
Demand	$65.4	$0.0	$0.0	$65.4	$16.1	$0.0	$0.0	$16.1	$0.0	$81.4
Demand Response	($0.0)	$0.0	$0.0	($0.0)	($0.0)	$0.0	$0.0	($0.0)	$0.0	($0.0)
Explicit Congestion Only	$0.0	$0.0	$1.2	$1.2	$0.0	$0.0	($0.8)	($0.8)	$0.0	$0.3
Explicit Congestion and Loss Only	$0.0	$0.0	($0.1)	$0.0	$0.0	$0.0	($0.0)	($0.0)	$0.0	($0.2)
Export	($30.2)	$0.0	($0.5)	($30.7)	($10.3)	$0.0	($7.6)	($17.9)	$0.0	($48.6)
Generation	$0.0	($564.9)	$0.0	$564.9	$0.0	$17.3	$0.0	($17.3)	$0.0	$547.6
Grandfathered Overuse	$0.0	$0.0	($0.5)	($0.5)	$0.0	$0.0	$0.4	$0.4	$0.0	($0.1)
Import	$0.0	($4.5)	$0.0	$4.5	$0.0	($31.9)	($2.6)	$29.3	$0.0	$33.8
INC	$0.0	($30.8)	$0.0	$30.8	$0.0	$30.2	$0.0	($30.2)	$0.0	$0.6
Internal Bilateral	$105.4	$105.5	$0.1	$0.0	($0.2)	($0.2)	$0.0	$0.0	$0.0	$0.0
Up to Congestion	$0.0	$0.0	($10.5)	($10.5)	$0.0	$0.0	$2.9	$2.9	$0.0	($7.6)
Wheel In	$0.0	$0.1	($0.1)	($0.2)	$0.0	($0.6)	($0.3)	$0.2	$0.0	$0.0
Wheel Out	$0.1	$0.0	$0.0	$0.1	($0.6)	$0.0	$0.0	($0.6)	$0.0	($0.4)
Total	$161.7	($494.5)	($10.4)	$645.9	($10.6)	$14.8	($8.1)	($33.6)	$0.0	$612.3

Zonal Congestion

Area Based Congestion

Area based congestion is the sum of credits and charges for every bus within a specified aggregate of pricing nodes, typically a load zone. When summed across a zone, the net congestion bill shows the overall congestion charge or credit for the buses in that zone, not including explicit congestion. This is a less meaningful measure of local congestion than constraint based congestion.

Because the net congestion bill for a zone only includes charges or credits incurred in the zone, the congestion bill for the zone is not a good measure of the amount of congestion (the difference between what load pays and generation is paid) paid by the zonal load. Zonal congestion calculations do not, for example, account for the difference between what the zonal load is paying in congestion charges relative to what the generation is paid that serves that load if the zone is a net importer or a net exporter of generation. Zonal congestion calculated for a zone that is a net importer of generation will tend to have overstated congestion, as the calculation does not account for external generation credits from external generation used to serve that load. Zonal congestion calculated for a zone that is a net exporter of generation will tend to have overstated generation congestion credits, as the calculation does not account for only the generation used to meet the zone's internal load.

Constraint Based Congestion

The constraint based congestion calculation is the correct method of calculating local congestion. Constraint based congestion includes all energy charges or credits incurred to serve zonal load. Constraint based congestion is the congestion paid by the zonal load. Constraint based congestion calculations account for the total difference between what the zonal load pays in congestion charges and what the generation that serves that load is paid, regardless of whether the zone is a net importer or a net exporter of generation.

Constraint based congestion calculates congestion on a constraint by constraint basis. On a system wide basis, congestion results from transmission constraints that prevent the lowest cost generation from serving some load that must be served by higher cost generation. Transmission constraints cause differences in LMP, defined by the marginal cost of resolving the constraint given the need to meet power balance requirements, indicated by the shadow price of the constraint. The LMP at any point is equal to the system marginal price (SMP) plus the shadow price of the constraint times the DFAX of the binding constraint to the bus in question (the CLMP of the constraint at that bus), plus marginal losses (MLMP).

The total congestion caused by a constraint is equal to the product of the constraint shadow price times the net flow on the binding constraint. Total congestion caused by the constraint can also be calculated using the CLMPs caused by the constraint at every bus and the net MW injections or MW withdrawals at every affected bus. Congestion associated with a specific constraint is equal to load congestion charges (CLMP of that specific constraint at each bus times load MW at each bus) caused by that constraint in excess of generation congestion credits (CLMP of that specific constraint at each bus times generation MW at each bus) caused by that constraint.

In order to define the load that is actually paying congestion, constraint specific congestion is assigned to downstream (positive CLMP) load buses that paid the congestion caused by the constraint, in proportion to the congestion charges collected from that load due to that constraint. The congestion collected from each load bus due to a constraint is equal to the CLMP caused by that constraint times the MW of load at that load bus. This calculation is done for both day-ahead congestion and balancing congestion.

Table 11-13 shows the area based and constraint based day-ahead and balancing congestion by zone for 2018. Table 11-14 shows the area based and constraint based congestion costs by zone for 2017.

Table 11-13 Area Based and Constraint Based total day ahead and total balancing congestion by zone (Dollars (Millions)): 2018

	Congestion Costs (Millions)					
	Area Based			Constraint Based		
Control Zone	Day-Ahead	Balancing	Total	Day-Ahead	Balancing	Total
AECO	$2.4	($5.4)	($3.0)	$16.9	($0.9)	$16.0
AEP	$358.2	($36.9)	$321.4	$234.9	($11.1)	$223.8
APS	$54.9	($1.1)	$53.8	$79.9	($3.4)	$76.5
ATSI	$96.0	($20.6)	$75.5	$102.9	($5.5)	$97.4
BGE	$57.5	($0.7)	$56.8	$48.1	($2.2)	$45.9
ComEd	$188.9	$45.2	$234.1	$172.3	($9.0)	$163.2
DAY	$16.8	($1.8)	$15.0	$27.9	($1.4)	$26.5
DEOK	$77.2	($10.1)	$67.1	$50.8	($2.1)	$48.7
DLCO	$5.8	$1.6	$7.4	$17.3	($1.1)	$16.2
Dominion	$105.5	($2.9)	$102.5	$158.9	($6.8)	$152.1
DPL	$54.2	($9.5)	$44.7	$87.8	($2.3)	$85.5
EKPC	($17.0)	$4.6	($12.4)	$24.0	($0.7)	$23.4
EXT	($2.2)	($14.4)	($16.6)	$1.4	($5.2)	($3.8)
JCPL	$19.4	($14.4)	$5.0	$39.2	($1.7)	$37.5
Met-Ed	$37.6	($5.7)	$31.8	$31.6	($1.6)	$29.9
OVEC	$0.4	($0.2)	$0.2	($0.0)	$0.0	$0.0
PECO	$103.3	($1.3)	$101.9	$62.4	($2.8)	$59.6
PENELEC	$75.4	($2.6)	$72.8	$32.1	($2.2)	$29.9
Pepco	$47.8	$3.8	$51.5	$44.6	($1.9)	$42.6
PPL	$45.1	$11.2	$56.3	$69.9	($2.6)	$67.3
PSEG	$52.7	($6.5)	$46.2	$73.4	($4.0)	$69.4
RECO	($1.2)	($1.0)	($2.2)	$2.6	($0.5)	$2.0
Total	$1,378.9	($69.0)	$1,309.9	$1,378.9	($69.0)	$1,309.9

Table 11-14 Area based and constraint based total day ahead and total balancing congestion by zone (Dollars (Millions)): 2017

Congestion Costs (Millions)						
	Area Based			Constraint Based		
Control Zone	Day-Ahead	Balancing	Total	Day-Ahead	Balancing	Total
AECO	($2.3)	($1.4)	($3.7)	$9.3	($0.6)	$8.7
AEP	$91.5	($9.6)	$81.8	$116.4	($7.5)	$108.9
APS	$20.7	($0.4)	$20.3	$31.1	($3.3)	$27.8
ATSI	$26.8	($7.2)	$19.5	$43.7	($4.2)	$39.5
BGE	$42.4	($2.5)	$39.9	$26.6	($1.9)	$24.7
ComEd	$231.9	($3.7)	$228.2	$161.8	($4.9)	$156.9
DAY	($1.4)	$1.5	$0.1	$12.2	($0.9)	$11.3
DEOK	$13.9	$5.1	$18.9	$21.8	($1.1)	$20.7
DLCO	$0.8	($1.4)	($0.6)	$7.6	($0.7)	$6.9
Dominion	$63.7	($10.0)	$53.7	$73.7	($6.3)	$67.3
DPL	($7.6)	$14.5	$6.9	$22.2	$13.0	$35.2
EKPC	($6.2)	$2.7	($3.6)	$10.6	($0.7)	$9.9
EXT	($10.1)	($14.7)	($24.8)	($1.9)	($2.5)	($4.4)
JCPL	$6.7	$0.8	$7.6	$21.2	($1.5)	$19.7
Met-Ed	$18.1	$1.5	$19.6	$16.5	($1.5)	$15.0
PECO	$79.5	($4.4)	$75.2	$36.3	($2.7)	$33.7
PENELEC	$57.8	($7.6)	$50.2	$16.2	($1.6)	$14.6
Pepco	$32.9	$6.2	$39.1	$24.2	($1.7)	$22.5
PPL	$28.8	$4.4	$33.3	$39.8	($2.2)	$37.5
PSEG	$46.2	($9.5)	$36.7	$42.2	($2.5)	$39.8
RECO	($1.1)	$0.1	($0.9)	$1.5	($0.1)	$1.4
Total	$733.1	($35.5)	$697.6	$733.1	($35.5)	$697.6

In cases where the constraint causes net negative congestion and/or there is no load bus on the constrained side of a binding constraint, the congestion of the constraint is handled as a special case. In these special cases the associated congestion is assigned to the control zone or residual load aggregate where the congestion is incurred and/or there are positive CLMPs from that constraint. Table 11-13 and Table 11-14 include congestion allocations from these special case constraints.

There are four basic categories of constraint specific allocation special cases: congestion associated with constraints with no downstream load bus (no load bus); congestion associated with constraints with downstream load buses with zero value CLMPs (zero CLMP); congestion associated with closed loop interface and CT price setting logic (closed loop and CT price setting logic) and congestion associated with nontransmission facility constraints in the Day-Ahead Energy Market and/or any unaccounted for difference between PJM billed congestion charges and calculated congestion costs including rounding errors (unclassified).

Table 11-15 and Table 11-16 break out the allocation of total congestion by each special case allocation method, congestion allocated by the standard method (allocation) and total allocation (total) by zone.

Table 11-15 and Table 11-16 show that closed loop interfaces and CT pricing logic generally result in negative congestion on a constraint specific basis. Through the assumption of artificial flexibility on the affected unit and artificially creating a constraint for which the otherwise inflexible resource can be marginal, PJM's use of both the closed loop interface and CT pricing logic forces the affected resource bus LMP to match the marginal offer of the resource.

Table 11-15 Constraint based total day-ahead and total balancing congestion by zone and special case logic (Dollars (Millions)): 2018

	Congestion Costs (Millions)												
	Day-Ahead						Balancing						
Control Zone	Load Bus Zero CLMP	Closed Loop Interfaces and CT	No Load Buses	Unclassified	Allocation	Total	Load Bus Zero CLMP	Closed Loop Interfaces and CT	No Load Buses	Unclassified	Allocation	Total	Grand Total
AECO	($0.0)	$0.1	$0.3	$0.0	$16.4	$16.9	$0.0	($0.0)	$0.0	($0.0)	($0.8)	($0.9)	$16.0
AEP	$0.3	$0.0	$0.5	($0.0)	$234.1	$234.9	$0.0	($2.3)	($0.0)	$0.2	($9.0)	($11.1)	$223.8
APS	$0.0	($0.3)	$0.0	($0.0)	$80.2	$79.9	$0.0	($0.1)	$0.0	($0.0)	($3.3)	($3.4)	$76.5
ATSI	$0.0	$0.5	$0.2	$0.0	$102.2	$102.9	$0.0	($0.2)	$0.0	($0.0)	($5.3)	($5.5)	$97.4
BGE	$0.0	($0.0)	$0.0	$0.0	$48.1	$48.1	$0.0	($0.1)	($0.0)	($0.0)	($2.1)	($2.2)	$45.9
ComEd	$1.4	($1.0)	$7.4	($0.0)	$164.4	$172.3	($0.0)	($2.1)	$0.2	$0.3	($7.5)	($9.0)	$163.2
DAY	$0.0	$0.1	$0.0	$0.0	$27.8	$27.9	$0.0	($0.2)	$0.0	$0.2	($1.4)	($1.4)	$26.5
DEOK	$0.2	$0.2	$2.0	$0.0	$48.5	$50.8	$0.0	$0.0	$0.0	$0.1	($2.2)	($2.1)	$48.7
DLCO	$0.0	$0.0	$0.0	($0.0)	$17.3	$17.3	$0.0	($0.0)	$0.0	$0.0	($1.1)	($1.1)	$16.2
Dominion	$0.0	$0.2	$0.4	$0.0	$158.3	$158.9	$0.0	($0.0)	($0.0)	($0.0)	($6.7)	($6.8)	$152.1
DPL	$0.1	$0.5	$0.4	$0.0	$86.8	$87.8	$0.0	($0.1)	$0.0	($0.1)	($2.1)	($2.3)	$85.5
EKPC	$0.0	($0.0)	$0.0	$0.0	$24.0	$24.0	$0.0	$0.1	$0.0	$0.1	($0.8)	($0.7)	$23.4
EXT	$0.0	$0.1	$0.9	$0.4	$0.0	$1.4	$0.0	($4.0)	($0.0)	($1.1)	$0.0	($5.2)	($3.8)
JCPL	$0.0	$0.7	$0.0	$0.0	$38.5	$39.2	$0.0	($0.1)	$0.0	($0.0)	($1.6)	($1.7)	$37.5
Met-Ed	$0.0	$0.2	$3.1	$0.0	$28.3	$31.6	($0.0)	($0.0)	($0.5)	$0.0	($1.1)	($1.6)	$29.9
OVEC	$0.0	($0.0)	$0.0	$0.0	$0.0	($0.0)	$0.0	$0.0	$0.0	$0.0	($0.0)	$0.0	$0.0
PECO	$0.0	($0.6)	$0.4	($0.0)	$62.6	$62.4	($0.0)	($0.1)	$0.0	$0.0	($2.7)	($2.8)	$59.6
PENELEC	$0.3	$0.1	$0.8	($0.0)	$30.8	$32.1	$0.0	$0.1	$0.0	$0.1	($2.4)	($2.2)	$29.9
Pepco	$0.0	$0.1	$0.0	$0.0	$44.5	$44.6	$0.0	$0.1	$0.0	($0.0)	($2.1)	($1.9)	$42.6
PPL	$0.1	($2.0)	$1.0	($0.0)	$70.8	$69.9	$0.0	$0.1	$0.0	$0.0	($2.7)	($2.6)	$67.3
PSEG	$0.0	($0.2)	$1.0	($0.0)	$72.6	$73.4	$0.0	($0.7)	$0.0	($0.0)	($3.3)	($4.0)	$69.4
RECO	$0.0	($0.1)	$0.0	$0.0	$2.6	$2.6	$0.0	($0.4)	$0.0	$0.0	($0.1)	($0.5)	$2.0
Total	$2.4	($1.3)	$18.5	$0.4	$1,358.8	$1,378.9	($0.0)	($10.2)	($0.3)	($0.4)	($58.2)	($69.0)	$1,309.9

Table 11-16 Constraint Based total day-ahead and total balancing congestion by zone and special case logic (Dollars (Millions)): 2017

	Congestion Costs (Millions)												
	Day-Ahead						Balancing						
Control Zone	Load Bus Zero CLMP	Closed Loop Interfaces and CT	No Load Buses	Unclassified	Allocation	Total	Load Bus Zero CLMP	Closed Loop Interfaces and CT	No Load Buses	Unclassified	Allocation	Total	Grand Total
AECO	$0.0	$0.3	$0.2	($0.0)	$8.9	$9.3	($0.0)	($0.0)	$0.0	$0.0	($0.6)	($0.6)	$8.7
AEP	$0.7	$0.9	$3.6	($0.0)	$111.2	$116.4	$0.0	($0.5)	($0.5)	$0.1	($6.6)	($7.5)	$108.9
APS	$0.0	($0.5)	$0.2	$0.0	$31.4	$31.1	$0.0	($0.2)	($0.4)	$0.0	($2.7)	($3.3)	$27.8
ATSI	$0.0	$1.0	$0.0	$0.0	$42.6	$43.7	$0.0	($0.7)	$0.0	$0.0	($3.5)	($4.2)	$39.5
BGE	$0.0	$0.5	($0.0)	$0.0	$26.1	$26.6	$0.0	($0.0)	$0.0	$0.0	($1.9)	($1.9)	$24.7
ComEd	$1.4	($1.3)	$11.3	($0.0)	$150.3	$161.8	($0.0)	$0.4	$0.2	$0.5	($6.0)	($4.9)	$156.9
DAY	($0.0)	$0.0	$0.0	$0.0	$12.2	$12.2	$0.0	$0.0	$0.0	$0.0	($0.9)	($0.9)	$11.3
DEOK	$0.1	($0.2)	$1.9	$0.0	$20.0	$21.8	$0.0	$0.2	($0.0)	$0.0	($1.4)	($1.1)	$20.7
DLCO	$0.0	($0.1)	$0.0	($0.0)	$7.6	$7.6	$0.0	$0.0	$0.0	$0.0	($0.7)	($0.7)	$6.9
Dominion	$0.0	$0.6	$0.1	$0.0	$72.9	$73.7	$0.0	($0.1)	$0.0	$0.0	($6.3)	($6.3)	$67.3
DPL	$0.1	($16.9)	$0.1	$0.0	$39.0	$22.2	($0.0)	$0.1	($0.0)	$0.0	$12.9	$13.0	$35.2
EKPC	$0.0	$0.0	$0.0	$0.0	$10.6	$10.6	$0.0	($0.0)	($0.0)	($0.0)	($0.7)	($0.7)	$9.9
EXT	($0.0)	($1.8)	($0.2)	$0.2	$0.0	($1.9)	$0.0	($0.9)	($0.0)	($1.6)	$0.0	($2.5)	($4.4)
JCPL	$0.0	$0.2	$0.0	$0.0	$21.0	$21.2	($0.0)	$0.0	$0.0	($0.1)	($1.4)	($1.5)	$19.7
Met-Ed	$0.1	($0.7)	$0.2	($0.0)	$17.0	$16.5	$0.0	($0.0)	$0.0	($0.0)	($1.5)	($1.5)	$15.0
PECO	$0.2	($2.1)	$0.8	($0.0)	$37.4	$36.3	$0.0	$0.0	$0.0	($0.0)	($2.7)	($2.7)	$33.7
PENELEC	$0.8	($2.1)	$1.2	($0.0)	$16.3	$16.2	$0.0	($0.7)	$0.0	$0.1	($1.0)	($1.6)	$14.6
Pepco	$0.0	$0.6	($0.0)	$0.0	$23.6	$24.2	$0.0	$0.0	$0.0	$0.0	($1.7)	($1.7)	$22.5
PPL	$0.3	($1.6)	$4.4	($0.0)	$36.7	$39.8	$0.0	($0.0)	$0.3	$0.0	($2.5)	($2.2)	$37.5
PSEG	$0.1	$0.0	$0.2	($0.0)	$42.0	$42.2	$0.0	($0.0)	$0.0	$0.2	($2.6)	($2.5)	$39.8
RECO	$0.0	($0.0)	$0.0	$0.0	$1.5	$1.5	$0.0	$0.0	$0.0	($0.0)	($0.1)	($0.1)	$1.4
Total	$3.8	($23.2)	$23.9	$0.2	$728.4	$733.1	$0.0	($2.4)	($0.4)	($0.8)	($31.8)	($35.5)	$697.6

Monthly Congestion

Table 11-17 shows that monthly total congestion costs ranged from $45.2 million in February to $535.9 million in January 2018.

The total day-ahead congestion costs from January 5, through January 8, 2018, were 47.2 percent ($244.5 million out of $517.7 million) of total day-ahead congestion costs in January 2018. The high total day-ahead congestion costs from January 5, 2018 through January 8, 2018, were mainly a result of the high negative generation credits caused by the AEP – DOM Interface, Cloverdale Transformer, Tanners Creek – Miami Fort Flowgate and 5004/5005 Interface constraints. The high gas prices and dispatch of high cost units resulted in high shadow prices for those constraints. The high negative CLMPs on the low side of those constraints caused high negative day-ahead generation credits on those days. Negative generation credits are positive congestion costs. Higher negative generation credits mean that generation was paid less and that the difference between load payments and generator credits (the difference is congestion) was therefore higher.

Congestion costs in May were the second highest after January. Most of the May congestion costs were in the day-ahead market where the congestion costs were significantly affected by the Graceton – Safe Harbor constraint.

Table 11-17 Monthly PJM congestion costs by market (Dollars (Millions)): 2017 and 2018

	Congestion Costs (Millions)							
	2017				2018			
	Day-Ahead Total	Balancing Total	Inadvertent Charges	Grand Total	Day-Ahead Total	Balancing Total	Inadvertent Charges	Grand Total
Jan	$66.4	($6.5)	($0.0)	$59.9	$517.7	$18.2	$0.0	$535.9
Feb	$44.4	$2.1	$0.0	$46.5	$43.8	$1.4	($0.0)	$45.2
Mar	$54.1	($2.5)	$0.0	$51.6	$80.2	($0.3)	$0.0	$79.9
Apr	$30.7	($0.1)	$0.0	$30.5	$57.4	($3.3)	$0.0	$54.1
May	$36.7	($4.0)	$0.0	$32.7	$122.2	($16.0)	$0.0	$106.2
Jun	$64.5	($0.2)	$0.0	$64.4	$95.2	($19.9)	$0.0	$75.3
Jul	$51.7	($10.4)	$0.0	$41.3	$70.8	($5.8)	$0.0	$65.0
Aug	$34.3	($4.2)	$0.0	$30.1	$69.2	($3.5)	$0.0	$65.7
Sep	$99.7	($1.2)	$0.0	$98.5	$95.2	($6.3)	($0.0)	$88.9
Oct	$50.8	$11.3	$0.0	$62.1	$95.0	($11.8)	($0.0)	$83.3
Nov	$59.9	($1.5)	($0.0)	$58.3	$69.1	($14.2)	($0.0)	$54.9
Dec	$139.8	($18.1)	($0.0)	$121.7	$63.0	($7.6)	$0.0	$55.5
Total	$733.1	($35.5)	$0.0	$697.6	$1,378.9	($69.0)	$0.0	$1,309.9

Figure 11-1 shows PJM monthly total congestion cost for 2008 through 2018.

Figure 11-1 PJM monthly total congestion cost (Dollars (Millions)): 2008 through 2018

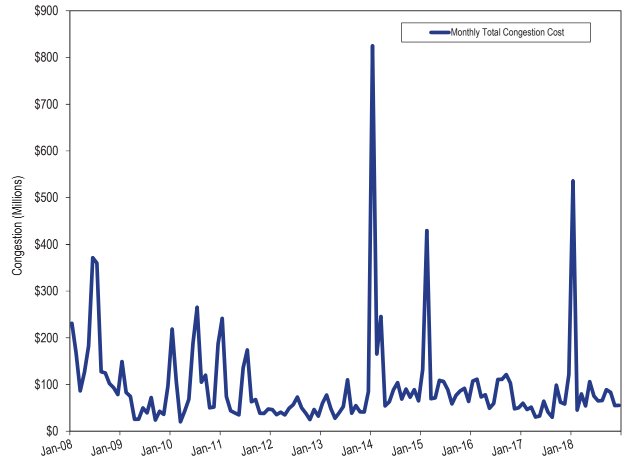


Table 11-18 and Table 11-19 show monthly total congestion costs for each virtual transaction type in 2018 and 2017. Virtual transaction congestion costs, when positive, are the total congestion cost (charge) to the virtual transaction and when negative, are the total congestion credit (payment) to the virtual transaction. The negative totals in Table 11-18 and Table 11-19 show that virtuals were paid in 2018 and in 2017. More than half the total payment to virtuals went to UTCs.

Table 11-18 Monthly PJM congestion costs by virtual transaction type and by market (Dollars (Millions)): 2018

	Congestion Costs (Millions)									
	DEC			INC			Up to Congestion			
	Day-Ahead	Balancing	Total	Day-Ahead	Balancing	Total	Day-Ahead	Balancing	Total	Grand Total
Jan	$4.1	($6.5)	($2.4)	$4.5	($8.1)	($3.6)	($40.8)	$29.5	($11.3)	($17.2)
Feb	$1.8	$0.4	$2.2	$1.2	($0.8)	$0.4	($0.5)	$1.3	$0.9	$3.5
Mar	$0.9	($2.8)	($1.9)	$1.4	($3.2)	($1.8)	($5.1)	$2.0	($3.1)	($6.8)
Apr	$0.4	($0.7)	($0.4)	$1.8	($1.4)	$0.4	($1.0)	$1.0	($0.1)	($0.1)
May	$1.5	($4.1)	($2.6)	$4.5	($6.9)	($2.5)	$1.7	($10.6)	($8.9)	($14.0)
Jun	$3.6	($2.4)	$1.1	$3.0	($3.7)	($0.7)	$5.6	($4.4)	$1.2	$1.6
Jul	$1.3	($2.4)	($1.1)	$0.8	($0.7)	$0.1	$2.3	($2.8)	($0.5)	($1.5)
Aug	$2.4	($3.1)	($0.6)	$0.2	($0.2)	$0.1	$3.4	($2.8)	$0.7	$0.1
Sep	$2.1	($1.6)	$0.5	$1.4	($1.5)	($0.1)	$4.8	($6.9)	($2.1)	($1.7)
Oct	$1.5	($2.6)	($1.1)	$2.4	($3.2)	($0.8)	$2.5	($3.3)	($0.8)	($2.7)
Nov	$2.1	($3.3)	($1.2)	$0.4	($2.3)	($1.9)	$4.3	($7.5)	($3.2)	($6.3)
Dec	$3.7	($3.5)	$0.1	($1.2)	$2.0	$0.8	$3.4	($3.5)	($0.1)	$0.8
Total	$25.3	($32.7)	($7.4)	$20.5	($30.0)	($9.5)	($19.4)	($7.9)	($27.4)	($44.3)

Table 11-19 Monthly PJM congestion costs by virtual transaction type and by market (Dollars (Millions)): 2017

	Congestion Costs (Millions)									
	DEC			INC			Up to Congestion			
	Day-Ahead	Balancing	Total	Day-Ahead	Balancing	Total	Day-Ahead	Balancing	Total	Grand Total
Jan	$1.1	($3.0)	($2.0)	$0.3	($1.1)	($0.8)	$2.9	($2.0)	$1.0	($1.9)
Feb	($0.7)	($1.6)	($2.3)	($4.9)	$3.4	($1.5)	$0.7	$1.7	$2.4	($1.4)
Mar	($1.2)	$0.4	($0.8)	$2.3	($2.6)	($0.3)	($1.4)	$1.2	($0.3)	($1.3)
Apr	($1.5)	$1.3	($0.2)	$0.2	($0.6)	($0.4)	$0.7	$0.6	$1.4	$0.8
May	($3.5)	$1.7	($1.8)	$1.4	($3.2)	($1.8)	$0.2	$0.6	$0.9	($2.7)
Jun	($0.3)	$0.2	($0.2)	$1.0	($1.5)	($0.5)	($0.3)	$1.4	$1.1	$0.4
Jul	$0.6	($2.2)	($1.7)	$1.1	($3.2)	($2.1)	$1.0	($5.1)	($4.1)	($7.9)
Aug	$2.0	($2.1)	($0.1)	$0.4	($1.3)	($0.9)	$1.6	($2.7)	($1.2)	($2.2)
Sep	$2.3	($2.6)	($0.3)	$0.9	($2.2)	($1.3)	($3.8)	($2.7)	($6.5)	($8.1)
Oct	$1.8	($2.5)	($0.7)	($8.6)	$7.6	($1.0)	($3.9)	$3.8	($0.1)	($1.9)
Nov	$2.0	($3.1)	($1.1)	($4.3)	$3.0	($1.3)	$1.0	($2.1)	($1.1)	($3.5)
Dec	$1.9	($3.6)	($1.7)	($0.2)	$1.9	$1.7	($7.6)	($5.5)	($13.1)	($13.1)
Total	$4.3	($17.1)	($12.8)	($10.3)	$0.2	($10.2)	($8.9)	($10.8)	($19.7)	($42.7)

Congested Facilities

A congestion event exists when a unit or units must be dispatched out of merit order to control for the potential impact of a contingency on a monitored facility or to control an actual overload. A congestion event hour exists when a specific facility is constrained for one or more five-minute intervals within an hour. A congestion event hour differs from a constrained hour, which is any hour during which one or more facilities are congested. Thus, if two facilities are constrained during an hour, the result is two congestion event hours and one constrained hour. Constraints are often simultaneous, so the number of congestion event hours usually exceeds the number of constrained hours and the number of congestion event hours usually exceeds the number of hours in a year.

In order to have a consistent metric for real-time and day-ahead congestion frequency, real-time congestion frequency is measured using the convention that an hour is constrained if any of its component five-minute intervals is constrained. This is consistent with the way in which PJM reports real-time congestion. In 2018, there were 132,598 day-ahead, congestion event hours compared to 300,923 day-ahead congestion event hours in 2017. Of the 2018 day-ahead congestion event hours, only 9,965 (7.5 percent) were also constrained in the Real-Time Energy Market. In 2018, there were 22,910 real-time, congestion event hours compared to 22,393 real-time, congestion event hours in 2017. Of 2018 real-time congestion event hours, 10,071 (44.0 percent) were also constrained in the Day-Ahead Energy Market.

The top five constraints by congestion costs contributed $375.6 million, or 28.7 percent, of the total PJM congestion costs in 2018. The top five constraints were the AEP – DOM Interface, the Cloverdale Transformer, the Graceton - Safe Harbor Line, the Tanners Creek – Miami Fort Flowgate, and the 5004/5005 Interface.

The change in the location of the top 10 constraints between 2017 and 2018 was a result of the increased gas prices in January 2018 and the use of high price oil fired units to control for contingencies caused by outages related to transmission upgrades in Virginia in May 2018 (Figure 11-2).

When gas prices are low compared to coal prices, as they were for the bulk of 2017, generation offers tend to be lower in the eastern and central part of PJM than in the rest of PJM. This causes constraints between the eastern and central part of PJM and the rest of PJM to be the largest contributors to congestion.

When gas prices are high compared to coal prices, as they were in January of 2018, generation offers tend to be lower in the western region of PJM than in the rest of PJM. This causes constraints between western region and the southeast to be the largest contributors to congestion.

Congestion by Facility Type and Voltage

Day-ahead, congestion event hours decreased on all types of facilities as a result of a significant decrease in UTC activities caused by the February 20, 2018, FERC order implemented by PJM on February 22, 2018.[18] The order limited UTC trading to hubs, residual metered load, and interfaces.

Real-time, congestion event hours increased on lines and decreased on flowgates, interfaces and transformers. The increase on lines was primarily a result of the increase on lines in the AEP and BGE control zones. The decrease in real-time, congestion event hours on flowgates was primarily a result of the fact that none of the NYISO flowgates were binding in 2018.

Day-ahead congestion costs increased on all types of facilities in 2018 compared to 2017. Day-ahead generation credits decreased on all types of facilities in 2018 compared to 2017. The high negative day-ahead generation credits were mainly a result of high gas prices and dispatch of high cost units, which caused high shadow prices for some constraints in the early part of January. The high negative CLMPs on the low side of those constraints caused high negative day-ahead generation credits. Negative generation credits are positive congestion costs.

Balancing congestion costs increased on interfaces and transformers and decreased on flowgates and lines in 2018 compared to 2017. Table 11-20 provides congestion event hour subtotals and congestion cost subtotals comparing 2018 results by facility type: line, transformer, interface, flowgate and unclassified facilities.[19] [20]

Table 11-21 presents this information for 2017.

Table 11-20 Congestion summary (By facility type): 2018

	Congestion Costs (Millions)										
	Day-Ahead				Balancing					Event Hours	
Type	Load Payments	Generation Credits	Explicit Costs	Total	Load Payments	Generation Credits	Explicit Costs	Total	Grand Total	Day-Ahead	Real-Time
Flowgate	($56.0)	($338.9)	($36.4)	$246.4	$2.0	$7.3	($2.9)	($8.2)	$238.2	19,816	5,585
Interface	$65.0	($163.6)	($13.9)	$214.6	$15.2	$22.8	$11.1	$3.6	$218.2	2,316	397
Line	$257.2	($387.1)	$28.1	$672.4	($10.1)	$29.3	($25.6)	($65.0)	$607.4	78,963	14,310
Transformer	$64.4	($141.4)	$1.7	$207.5	$0.4	$2.9	$4.0	$1.5	$209.0	26,714	1,568
Other	$18.6	($17.5)	$1.5	$37.6	$3.0	($1.0)	($4.4)	($0.4)	$37.1	4,789	1,050
Unclassified	$0.2	($0.1)	$0.1	$0.4	$1.0	$0.7	($0.7)	($0.4)	$0.0	NA	NA
Total	$349.3	($1,048.6)	($18.9)	$1,378.9	$11.5	$62.0	($18.5)	($69.0)	$1,309.9	132,598	22,910

18 162 FERC ¶ 61,139.

19 Unclassified are congestion costs related to nontransmission facility constraints in the Day-Ahead Energy Market and any unaccounted for difference between PJM billed congestion charges and calculated congestion costs including rounding errors. Nontransmission facility constraints include day-ahead market only constraints such as constraints on virtual transactions and constraints associated with phase-angle regulators.

20 The term flowgate refers to MISO reciprocal coordinated flowgates and NYISO M2M flowgates.

Table 11-21 Congestion summary (By facility type): 2017

	Congestion Costs (Millions)										
	Day-Ahead				Balancing					Event Hours	
Type	Load Payments	Generation Credits	Explicit Costs	Total	Load Payments	Generation Credits	Explicit Costs	Total	Grand Total	Day-Ahead	Real-Time
Flowgate	($52.9)	($207.3)	($24.6)	$129.8	$7.2	$6.0	($3.3)	($2.1)	$127.7	29,579	5,969
Interface	$16.0	($58.8)	($7.0)	$67.8	$5.1	$14.2	$5.7	($3.4)	$64.4	4,635	441
Line	$186.3	($233.0)	$12.6	$431.9	$5.3	$20.5	($0.1)	($15.2)	$416.7	155,443	12,961
Transformer	$33.2	($48.7)	$9.4	$91.3	$3.8	$4.0	($13.9)	($14.1)	$77.2	94,643	2,493
Other	$4.9	($6.2)	$1.0	$12.1	$0.6	$1.3	$0.9	$0.2	$12.3	16,623	529
Unclassified	$0.1	($0.0)	$0.0	$0.2	$0.2	$1.2	$0.2	($0.8)	($0.7)	NA	NA
Total	$187.6	($554.1)	($8.6)	$733.1	$22.2	$47.2	($10.4)	($35.5)	$697.6	300,923	22,393

Table 11-22 and Table 11-23 compare day-ahead and real-time congestion event hours. Among the hours for which a facility is constrained in the Day-Ahead Energy Market, the number of hours during which the facility is also constrained in the Real-Time Energy Market are presented in Table 11-22. In 2018, there were 132,598 congestion event hours in the Day-Ahead Energy Market. Of those day-ahead congestion event hours, only 9,965 (7.5 percent) were also constrained in the Real-Time Energy Market. There were 88,078 congestion event hours in the Day-Ahead Energy Market for the period February 22, 2018 through December 31, 2018. Of those day-ahead congestion event hours, only 8,060 (9.2 percent) were also constrained in the Real-Time Energy Market. In 2017, of the 300,923 day-ahead congestion event hours, only 11,961 (4.0 percent) were binding in the Real-Time Energy Market.[21]

Among the hours for which a facility was constrained in the Real-Time Energy Market, the number of hours during which the facility was also constrained in the Day-Ahead Energy Market are presented in Table 11-23. In 2018, of the 22,910 congestion event hours in the Real-Time Energy Market, 10,071 (44.0 percent) were also constrained in the Day-Ahead Energy Market. In 2017, of the 22,393 real-time congestion event hours, 11,733 (52.4 percent) were also in the Day-Ahead Energy Market.

Table 11-22 Congestion event hours (day-ahead against real-time): 2017 and 2018

	Congestion Event Hours					
	2017			2018		
Type	Day-Ahead Constrained	Corresponding Real-Time Constrained	Percent	Day-Ahead Constrained	Corresponding Real-Time Constrained	Percent
Flowgate	29,579	2,464	8.3%	19,816	2,017	10.2%
Interface	4,635	268	5.8%	2,316	239	10.3%
Line	155,443	7,972	5.1%	78,963	6,504	8.2%
Transformer	94,643	968	1.0%	26,714	702	2.6%
Other	16,623	289	1.7%	4,789	503	10.5%
Total	300,923	11,961	4.0%	132,598	9,965	7.5%

Table 11-23 Congestion event hours (real-time against day-ahead): 2017 and 2018

	Congestion Event Hours					
	2017			2018		
Type	Real-Time Constrained	Corresponding Day-Ahead Constrained	Percent	Real-Time Constrained	Corresponding Day-Ahead Constrained	Percent
Flowgate	5,969	2,473	41.4%	5,585	2,019	36.2%
Interface	441	333	75.5%	397	264	66.5%
Line	12,961	7,722	59.6%	14,310	6,566	45.9%
Transformer	2,493	916	36.7%	1,568	708	45.2%
Other	529	289	54.6%	1,050	514	49.0%
Total	22,393	11,733	52.4%	22,910	10,071	44.0%

21 Constraints are mapped to transmission facilities. In the Day-Ahead Energy Market, within a given hour, a single facility may be associated with multiple constraints. In such situations, the same facility accounts for more than one constraint-hour for a given hour in the Day-Ahead Energy Market. Similarly in the real-time market a facility may account for more than one constraint-hour within a given hour.

Table 11-24 shows congestion costs by facility voltage class for 2018. Congestion costs in 2018 increased for all facilities except 34 kV or 18 kV facilities compared to 2017, caused by the large increase in day-ahead congestion costs in January 2018 (Table 11-25).

Table 11-24 Congestion summary (By facility voltage): 2018

	Congestion Costs (Millions)										
	Day-Ahead				Balancing					Event Hours	
Voltage (kV)	Load Payments	Generation Credits	Explicit Costs	Total	Load Payments	Generation Credits	Explicit Costs	Total	Grand Total	Day-Ahead	Real-Time
765	$0.5	($1.6)	$0.2	$2.3	$0.7	$0.3	($0.0)	$0.4	$2.6	106	21
500	$89.2	($183.2)	($13.6)	$258.7	$16.6	$21.2	$11.5	$6.9	$265.6	3,951	994
345	$12.2	($271.6)	$1.1	$284.9	$0.3	($0.9)	($12.6)	($11.5)	$273.4	20,762	2,785
230	$182.3	($70.1)	$4.5	$256.9	($1.2)	$7.7	($1.2)	($10.1)	$246.8	22,259	5,686
212	$0.0	($0.0)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	43	0
161	$1.4	($4.4)	($0.5)	$5.3	$0.3	($0.4)	$0.5	$1.1	$6.4	356	85
138	($2.2)	($455.0)	($14.0)	$438.8	$2.8	$26.3	($10.0)	($33.5)	$405.3	50,411	9,324
115	$7.3	($71.7)	($3.1)	$75.9	($0.7)	$3.7	$0.4	($4.0)	$71.9	14,078	1,996
69	$58.2	$9.6	$6.1	$54.7	($8.2)	$3.4	($6.4)	($17.9)	$36.7	17,281	1,958
34	$0.1	$0.0	$0.3	$0.4	$0.0	$0.1	$0.0	($0.0)	$0.4	2,127	61
18	($0.0)	($0.3)	$0.1	$0.4	$0.0	$0.0	$0.0	$0.0	$0.4	309	0
13.2	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	55	0
13	$0.0	($0.1)	$0.0	$0.1	$0.0	$0.0	$0.0	$0.0	$0.1	291	0
12	$0.0	($0.1)	$0.0	$0.2	$0.0	$0.0	$0.0	$0.0	$0.2	569	0
Unclassified	$0.2	($0.1)	$0.1	$0.4	$1.0	$0.7	($0.7)	($0.4)	$0.0	NA	NA
Total	$349.3	($1,048.6)	($18.9)	$1,378.9	$11.5	$62.0	($18.5)	($69.0)	$1,309.9	132,598	22,910

Table 11-25 Congestion summary (By facility voltage): 2017

	Congestion Costs (Millions)										
	Day-Ahead				Balancing					Event Hours	
Voltage (kV)	Load Payments	Generation Credits	Explicit Costs	Total	Load Payments	Generation Credits	Explicit Costs	Total	Grand Total	Day-Ahead	Real-Time
765	$0.6	($1.2)	$0.8	$2.6	($0.2)	$0.0	$0.0	($0.2)	$2.4	1,070	35
500	$74.5	($70.2)	($5.7)	$138.9	$7.9	$17.3	$8.8	($0.6)	$138.4	9,061	1,535
345	($11.0)	($140.4)	$1.0	$130.4	$8.4	$9.4	($16.9)	($17.9)	$112.5	59,380	3,219
230	$121.0	($47.5)	$1.6	$170.1	$6.8	$18.9	($1.7)	($13.8)	$156.3	47,474	5,750
161	($0.0)	($0.3)	($0.0)	$0.3	$0.1	($0.0)	$0.1	$0.2	$0.4	33	34
138	($10.6)	($266.5)	($4.1)	$251.8	$4.3	$13.3	($5.0)	($13.9)	$237.9	128,573	8,787
115	$3.7	($34.5)	$0.1	$38.2	($0.7)	$2.2	$1.3	($1.6)	$36.6	30,626	1,913
69	$9.1	$7.2	($2.7)	($0.9)	($4.6)	($15.1)	$2.7	$13.2	$12.4	17,329	1,120
35	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	15	0
34	$0.3	$0.0	$0.2	$0.5	$0.0	$0.0	$0.0	$0.0	$0.5	5,573	0
18	($0.0)	($0.6)	$0.2	$0.8	$0.0	$0.0	$0.0	$0.0	$0.8	1,677	0
17	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	11	0
13	$0.0	($0.0)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	101	0
Unclassified	$0.1	($0.0)	$0.0	$0.2	$0.2	$1.2	$0.2	($0.8)	($0.7)	NA	NA
Total	$187.6	($554.1)	($8.6)	$733.1	$22.2	$47.2	($10.4)	($35.5)	$697.6	300,923	22,393

Constraint Duration

Table 11-26 lists the constraints for 2017 and 2018 that were most frequently binding and Table 11-27 shows the constraints which experienced the largest change in congestion event hours from 2017 to 2018. In Table 11-26, constraints are presented in descending order of total day-ahead event hours and real-time event hours for 2018. In Table 11-27, the constraints are presented in descending order of absolute value of day-ahead event hour changes plus real-time event hour changes from 2017 to 2018.

Table 11-26 Top 25 constraints with frequent occurrence: 2017 and 2018

			Event Hours						Percent of Annual Hours					
			Day-Ahead			Real-Time			Day-Ahead			Real-Time		
No.	Constraint	Type	2017	2018	Change	2017	2018	Change	2017	2018	Change	2017	2018	Change
1	Graceton - Safe Harbor	Line	3,118	3,361	243	1,151	2,046	895	36%	38%	3%	13%	23%	10%
2	Easton - Emuni	Line	1,987	3,831	1,844	1	2	1	23%	44%	21%	0%	0%	0%
3	Monroe - Vineland	Line	343	2,858	2,515	13	500	487	4%	33%	29%	0%	6%	6%
4	Gardners - Texas East	Line	1,317	2,788	1,471	116	439	323	15%	32%	17%	1%	5%	4%
5	Quad Cities	Trf	9,457	2,614	(6,843)	0	0	0	108%	30%	(78%)	0%	0%	0%
6	Emilie - Falls	Line	5,171	1,593	(3,578)	894	329	(565)	59%	18%	(41%)	10%	4%	(6%)
7	Fargo	Flowgate	0	1,308	1,308	0	510	510	0%	15%	15%	0%	6%	6%
8	Newton	Flowgate	789	1,283	494	173	426	253	9%	15%	6%	2%	5%	3%
9	Lakeview - Greenfield	Line	1,593	1,356	(237)	164	352	188	18%	15%	(3%)	2%	4%	2%
10	Roxana - Praxair	Flowgate	1,734	1,132	(602)	290	481	191	20%	13%	(7%)	3%	5%	2%
11	North Salisbury - Rockawalkin	Line	0	1,610	1,610	0	0	0	0%	18%	18%	0%	0%	0%
12	Nottingham	Other	1,065	1,157	92	316	390	74	12%	13%	1%	4%	4%	1%
13	Conastone - Peach Bottom	Line	3,159	1,100	(2,059)	840	422	(418)	36%	13%	(24%)	10%	5%	(5%)
14	Quad Cities - Cordova	Flowgate	514	1,522	1,008	0	0	0	6%	17%	12%	0%	0%	0%
15	Tanners Creek - Miami Fort	Flowgate	74	1,511	1,437	0	0	0	1%	17%	16%	0%	0%	0%
16	Brokaw - Leroy	Flowgate	1,744	1,232	(512)	528	261	(267)	20%	14%	(6%)	6%	3%	(3%)
17	Delaware - Hogan	Line	1	1,227	1,226	0	235	235	0%	14%	14%	0%	3%	3%
18	Cedar Grove Sub - Roseland	Line	355	1,368	1,013	54	64	10	4%	16%	12%	1%	1%	0%
19	Berwick - Koonsville	Line	574	1,425	851	12	6	(6)	7%	16%	10%	0%	0%	(0%)
20	Olive	Other	6,460	1,327	(5,133)	0	0	0	74%	15%	(59%)	0%	0%	0%
21	Flint Lake - Luchtman Road	Flowgate	0	890	890	0	365	365	0%	10%	10%	0%	4%	4%
22	Zion	Line	4,644	1,193	(3,451)	0	0	0	53%	14%	(39%)	0%	0%	0%
23	Sayreville - Sayreville	Line	675	1,192	517	0	0	0	8%	14%	6%	0%	0%	0%
24	Tanners Creek - Miami Fort	Line	1,213	673	(540)	63	489	426	14%	8%	(6%)	1%	6%	5%
25	Maple - Jackson	Line	134	1,000	866	5	155	150	2%	11%	10%	0%	2%	2%

Table 11-27 Top 25 constraints with largest year to year change in occurrence: 2017 and 2018

			Event Hours						Percent of Annual Hours					
			Day-Ahead			Real-Time			Day-Ahead			Real-Time		
No.	Constraint	Type	2017	2018	Change	2017	2018	Change	2017	2018	Change	2017	2018	Change
1	Quad Cities	Trf	9,457	2,614	(6,843)	0	0	0	108%	30%	(78%)	0%	0%	0%
2	Olive	Other	6,460	1,327	(5,133)	0	0	0	74%	15%	(59%)	0%	0%	0%
3	Waukegan	Trf	5,226	1,083	(4,143)	0	0	0	60%	12%	(47%)	0%	0%	0%
4	Emilie - Falls	Line	5,171	1,593	(3,578)	894	329	(565)	59%	18%	(41%)	10%	4%	(6%)
5	Braidwood - East Frankfort	Line	4,171	203	(3,968)	301	144	(157)	48%	2%	(45%)	3%	2%	(2%)
6	East Bend	Trf	4,464	453	(4,011)	0	0	0	51%	5%	(46%)	0%	0%	0%
7	Hinchmans	Trf	4,378	773	(3,605)	0	0	0	50%	9%	(41%)	0%	0%	0%
8	Westwood	Flowgate	3,399	0	(3,399)	198	0	(198)	39%	0%	(39%)	2%	0%	(2%)
9	Zion	Line	4,644	1,193	(3,451)	0	0	0	53%	14%	(39%)	0%	0%	0%
10	Seneca	Trf	3,399	299	(3,100)	0	0	0	39%	3%	(35%)	0%	0%	0%
11	Loretto - Vienna	Line	3,950	936	(3,014)	60	5	(55)	45%	11%	(34%)	1%	0%	(1%)
12	Tanners Creek	Trf	3,461	402	(3,059)	0	0	0	40%	5%	(35%)	0%	0%	0%
13	Howard - Shelby	Line	3,041	0	(3,041)	0	0	0	35%	0%	(35%)	0%	0%	0%
14	Monroe - Vineland	Line	343	2,858	2,515	13	500	487	4%	33%	29%	0%	6%	6%
15	West Chicago	Trf	3,490	606	(2,884)	0	0	0	40%	7%	(33%)	0%	0%	0%
16	Saddlebrook	Trf	3,098	322	(2,776)	0	0	0	35%	4%	(32%)	0%	0%	0%
17	Cherry Valley	Trf	3,007	403	(2,604)	149	3	(146)	34%	5%	(30%)	2%	0%	(2%)
18	Elwood	Other	2,571	0	(2,571)	0	0	0	29%	0%	(29%)	0%	0%	0%
19	Conastone - Peach Bottom	Line	3,159	1,100	(2,059)	840	422	(418)	36%	13%	(24%)	10%	5%	(5%)
20	Electric Junction	Trf	2,914	436	(2,478)	0	2	2	33%	5%	(28%)	0%	0%	0%
21	Liquid Carbonics	Trf	2,586	147	(2,439)	0	0	0	30%	2%	(28%)	0%	0%	0%
22	Gould Street - Westport	Line	2,800	417	(2,383)	0	8	8	32%	5%	(27%)	0%	0%	0%
23	Essex Co. RRF	Trf	2,793	430	(2,363)	0	0	0	32%	5%	(27%)	0%	0%	0%
24	Maywood	Trf	2,540	207	(2,333)	0	0	0	29%	2%	(27%)	0%	0%	0%
25	West Moulton - City Of St. Marys	Line	2,677	399	(2,278)	0	0	0	31%	5%	(26%)	0%	0%	0%

Constraint Costs

Table 11-28 and Table 11-29 show the top constraints affecting congestion costs by facility for 2018 and 2017. The AEP – DOM Interface was the largest contributor to congestion costs in 2018, with $121.0 million in total congestion costs and 9.2 percent of the total PJM congestion costs in 2018.

Table 11-28 Top 25 constraints affecting PJM congestion costs (By facility): 2018[22]

				Congestion Costs (Millions)									Percent of Total PJM Congestion Costs
				Day-Ahead				Balancing					
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit Costs	Total	Load Payments	Generation Credits	Explicit Costs	Total	Grand Total	2018
1	AEP - DOM	Interface	500	$55.6	($66.9)	($5.3)	$117.2	$13.4	$18.7	$9.0	$3.8	$121.0	9.2%
2	Cloverdale	Transformer	AEP	$46.0	($40.9)	($0.8)	$86.1	($1.6)	$0.6	$3.6	$1.4	$87.5	6.7%
3	Tanners Creek - Miami Fort	Flowgate	MISO	($20.8)	($94.1)	($2.9)	$70.4	$0.0	$0.0	$0.0	$0.0	$70.4	5.4%
4	Graceton - Safe Harbor	Line	BGE	$95.3	$31.1	$2.4	$66.6	$0.6	$4.6	($1.6)	($5.6)	$61.0	4.7%
5	5004/5005 Interface	Interface	500	($15.4)	($54.4)	($4.4)	$34.6	$0.8	$1.7	$2.1	$1.1	$35.7	2.7%
6	Batesville - Hubble	Flowgate	MISO	($13.1)	($55.9)	($10.3)	$32.5	($0.6)	($2.2)	$0.3	$2.0	$34.5	2.6%
7	Conastone - Peach Bottom	Line	500	$29.8	$0.7	($0.2)	$28.9	$1.6	$0.8	($0.0)	$0.7	$29.6	2.3%
8	Pleasant View - Ashburn	Line	Dominion	$17.8	($8.4)	($0.9)	$25.4	$1.1	$1.1	$0.6	$0.6	$25.9	2.0%
9	Lakeview - Greenfield	Line	ATSI	($20.4)	($57.3)	($1.5)	$35.3	($1.4)	$8.9	$0.3	($10.0)	$25.3	1.9%
10	Bedington - Black Oak	Interface	500	$10.2	($14.0)	($1.4)	$22.7	$0.6	$0.7	$0.6	$0.5	$23.2	1.8%
11	Gardners - Texas East	Line	Met-Ed	($5.1)	($26.2)	($0.2)	$20.8	($0.3)	$0.1	$1.4	$1.0	$21.9	1.7%
12	Wescosville	Transformer	PPL	$3.2	($17.5)	($0.6)	$20.1	$0.4	$0.1	$0.9	$1.2	$21.3	1.6%
13	North Salisbury - Rockawalkin	Line	DPL	$26.4	$7.3	$1.7	$20.8	$0.0	$0.0	$0.0	$0.0	$20.8	1.6%
14	AP South	Interface	500	$14.1	($8.3)	($1.6)	$20.8	$0.1	$0.1	($0.0)	($0.0)	$20.8	1.6%
15	Capitol Hill - Chemical	Line	AEP	$12.3	($5.0)	$0.5	$17.9	$0.8	($0.8)	($0.1)	$1.5	$19.4	1.5%
16	Nottingham	Other	PECO	$20.5	$2.6	$0.7	$18.7	$0.0	$0.0	$0.0	$0.0	$18.7	1.4%
17	Maple - Jackson	Line	ATSI	($13.1)	($28.6)	$2.1	$17.7	$0.4	$0.8	($0.9)	($1.3)	$16.4	1.3%
18	Person - Sedge Hill	Line	Dominion	$16.9	$2.3	$1.7	$16.3	($0.2)	($0.9)	($1.0)	($0.4)	$15.9	1.2%
19	Cedar Creek - Red Lion	Line	DPL	$2.4	($12.1)	$0.8	$15.3	($0.8)	($1.8)	($0.6)	$0.4	$15.7	1.2%
20	Conastone - Northwest	Line	BGE	$14.6	($0.9)	($0.6)	$15.0	($1.1)	($0.4)	$0.8	$0.0	$15.0	1.1%
21	Northport - Albion	Flowgate	MISO	($2.3)	($18.4)	($3.8)	$12.3	($0.2)	($1.1)	$1.3	$2.2	$14.5	1.1%
22	Brokaw - Leroy	Flowgate	MISO	$0.8	($12.3)	($4.4)	$8.6	$0.5	($1.3)	$3.0	$4.8	$13.5	1.0%
23	Krendale - Shanorma	Line	APS	($8.4)	($19.9)	$1.3	$12.8	$0.0	$0.0	$0.0	$0.0	$12.8	1.0%
24	Emilie - Falls	Line	PECO	$3.4	($7.6)	$0.4	$11.4	$0.2	$0.4	$0.4	$0.2	$11.6	0.9%
25	North Salisbury - Rockawalkin	Line	DPL	$0.0	$0.0	$0.0	$0.0	($4.6)	$4.2	($2.8)	($11.5)	($11.5)	(0.9%)
	Top 25 Total			$270.8	($504.7)	($27.3)	$748.1	$9.8	$34.5	$17.3	($7.4)	$740.7	56.5%
	All Other Constraints			$78.5	($543.9)	$8.4	$630.8	$1.7	$27.5	($35.9)	($61.6)	$569.2	43.5%
	Total			$349.3	($1,048.6)	($18.9)	$1,378.9	$11.5	$62.0	($18.5)	($69.0)	$1,309.9	100.0%

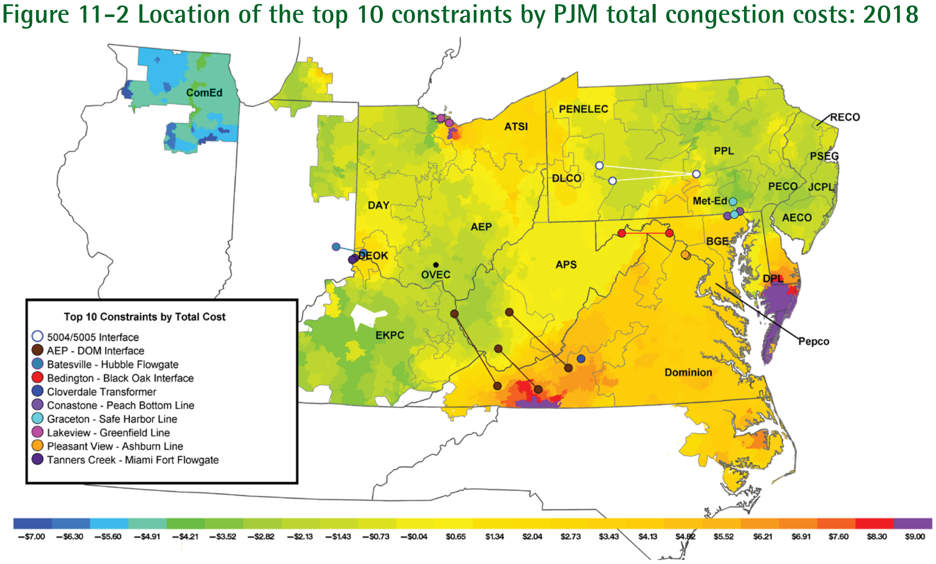
22 All flowgates are mapped to MISO as Location if they are flowgates coordinated by both PJM and MISO regardless of the location of the flowgates.

Table 11-29 Top 25 constraints affecting PJM congestion costs (By facility): 2017[23]

				Congestion Costs (Millions)									Percent of Total PJM Congestion Costs
				Day-Ahead				Balancing					
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit Costs	Total	Load Payments	Generation Credits	Explicit Costs	Total	Grand Total	2017
1	Braidwood - East Frankfort	Line	ComEd	($4.7)	($49.7)	$0.3	$45.3	$0.7	$1.9	($0.7)	($1.9)	$43.4	6.2%
2	Conastone - Peach Bottom	Line	500	$38.7	$1.6	$0.1	$37.2	$1.7	$1.2	$1.6	$2.0	$39.3	5.6%
3	Emilie - Falls	Line	PECO	$12.0	($13.6)	($0.1)	$25.6	$0.0	$1.2	$0.8	($0.4)	$25.2	3.6%
4	Graceton - Safe Harbor	Line	BGE	$30.2	$7.1	($0.0)	$23.1	$1.5	$2.2	$1.5	$0.7	$23.8	3.4%
5	5004/5005 Interface	Interface	500	($9.9)	($38.7)	($3.8)	$25.0	$4.5	$11.4	$4.6	($2.4)	$22.7	3.3%
6	AP South	Interface	500	$15.3	($9.2)	($2.4)	$22.1	($0.0)	$1.3	$0.9	($0.5)	$21.6	3.1%
7	Westwood	Flowgate	MISO	($22.1)	($41.3)	$0.5	$19.7	$1.2	$0.8	($0.5)	($0.1)	$19.6	2.8%
8	Cherry Valley	Transformer	ComEd	$8.9	($10.1)	$2.1	$21.0	($0.6)	$0.9	($0.9)	($2.3)	$18.7	2.7%
9	Carson - Rawlings	Line	Dominion	$14.5	($4.3)	$0.8	$19.6	$1.1	$1.8	($0.8)	($1.5)	$18.1	2.6%
10	Conastone - Otter Creek	Line	PPL	$23.0	$8.5	($0.6)	$13.9	$1.3	$1.6	$1.4	$1.2	$15.1	2.2%
11	Conastone - Northwest	Line	BGE	$12.7	($1.1)	($0.4)	$13.4	$0.3	$0.7	$1.0	$0.6	$14.0	2.0%
12	Three Mile Island	Transformer	500	$7.4	($4.9)	($0.3)	$11.9	($0.1)	($0.5)	$0.9	$1.3	$13.3	1.9%
13	Butler - Shanor Manor	Line	APS	($10.5)	($20.9)	$1.0	$11.4	$1.7	$1.7	($0.4)	($0.3)	$11.1	1.6%
14	Lakeview - Greenfield	Line	ATSI	($3.5)	($14.5)	$0.2	$11.2	$0.1	$0.7	$0.3	($0.4)	$10.8	1.5%
15	Alpine - Belvidere	Flowgate	MISO	($2.3)	($14.0)	($0.9)	$10.8	$0.0	$0.0	$0.0	$0.0	$10.8	1.5%
16	Bedington - Black Oak	Interface	500	$5.5	($4.1)	($0.2)	$9.3	$0.1	$0.3	$0.4	$0.2	$9.5	1.4%
17	Lake George - Aetna	Flowgate	MISO	($1.1)	($9.0)	($1.5)	$6.4	($2.2)	$0.9	$5.9	$2.7	$9.1	1.3%
18	Person - Sedge Hill	Line	Dominion	$16.2	$3.5	$2.0	$14.7	$0.7	$3.0	($3.3)	($5.6)	$9.1	1.3%
19	Batesville - Hubble	Flowgate	MISO	($5.5)	($19.4)	($4.5)	$9.4	($0.1)	($1.3)	($1.7)	($0.5)	$8.9	1.3%
20	Byron - Cherry Valley	Flowgate	MISO	($0.9)	($9.3)	($0.4)	$8.0	$0.0	$0.0	$0.0	$0.0	$8.0	1.1%
21	AEP - DOM	Interface	500	$3.3	($4.3)	($0.1)	$7.5	$0.5	$0.4	$0.2	$0.3	$7.8	1.1%
22	Brunner Island - Yorkanna	Line	Met-Ed	$6.0	($1.6)	($0.3)	$7.3	($0.0)	($0.1)	$0.1	$0.2	$7.4	1.1%
23	Brokaw - Leroy	Flowgate	MISO	$0.8	($7.6)	($3.7)	$4.8	$0.2	$0.3	$2.6	$2.5	$7.3	1.0%
24	Loretto - Vienna	Line	DPL	$8.8	$2.3	$0.7	$7.2	($0.4)	$0.1	$0.2	($0.3)	$6.9	1.0%
25	Pleasant View - Ashburn	Line	Dominion	$5.8	($3.7)	($0.3)	$9.1	($1.2)	$1.0	($0.1)	($2.3)	$6.8	1.0%
	Top 25 Total			$148.5	($258.1)	($11.7)	$395.0	$11.0	$31.8	$14.0	($6.7)	$388.3	55.7%
	All Other Constraints			$39.0	($295.9)	$3.1	$338.1	$11.2	$15.4	($24.5)	($28.7)	$309.3	44.3%
	Total			$187.6	($554.1)	($8.6)	$733.1	$22.2	$47.2	($10.4)	($35.5)	$697.6	100.0%

Figure 11-2 shows the locations of the top 10 constraints by total congestion costs on a contour map of the real-time, load-weighted average CLMP in 2018. Figure 11-3 shows the locations of the top 10 constraints by balancing congestion costs on a contour map of the real-time, load-weighted average CLMP in 2018. Figure 11-4 shows the locations of the top 10 constraints by day-ahead congestion costs on a contour map of the day-ahead, load-weighted average CLMP in 2018.

Figure 11-2 Location of the top 10 constraints by PJM total congestion costs: 2018



23 All flowgates are mapped to MISO as Location if they are flowgates coordinated by both PJM and MISO regardless the location of the flowgates.

Figure 11-3 Location of the top 10 constraints by PJM balancing congestion costs: 2018

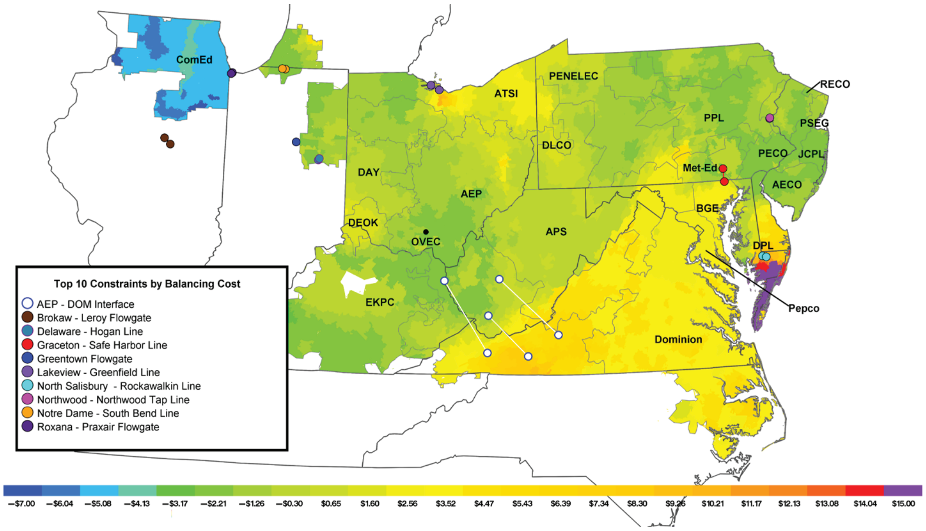
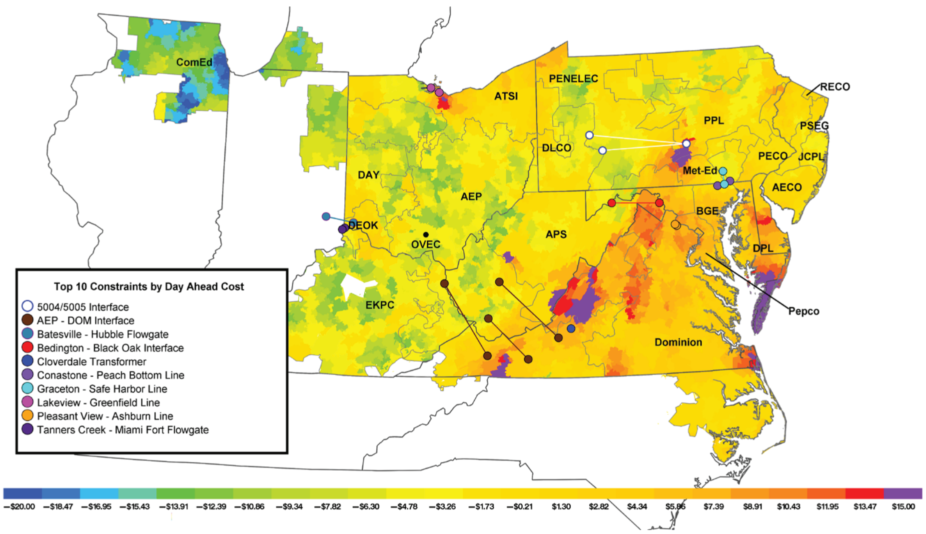


Figure 11-4 Location of the top 10 constraints by PJM day-ahead congestion costs: 2018



Constraint Specific Contribution to Area Based and Constraint Based Zonal Congestion

Constraints can affect prices and congestion across multiple zones. PJM is comprised of three regions: the PJM Mid-Atlantic Region with 11 control zones (the AECO, BGE, DPL, JCPL, Met-Ed, PECO, PENELEC, Pepco, PPL, PSEG and RECO control zones); the PJM West Region with nine control zones (the AP, ATSI, ComEd, AEP, DLCO, DEOK, DAY, EKPC and OVEC control zones); and the PJM South Region with one control zone (the Dominion Control Zone).[24]

Table 11-30 through Table 11-50 present the congestion costs of the top 20 constraints affecting each control zone using both area based calculations and constraint based calculations, including the facility type, the location of the constrained facility, day-ahead event hours and real-time event hours for 2018. The tables present the top 20 constraints in descending order of the absolute value of congestion costs for each zone using constraint based

24 See PJM Operating Agreement § 1.

calculations. In addition to the top 20 constraints, these tables show the congestion costs of all other constraints affecting the control zone.

Mid-Atlantic Region Congestion-Event Summaries

AECO Control Zone

Table 11-30 AECO Control Zone top congestion cost impacts (By facility): 2018

				Congestion Costs (Millions)							
				Area Based			Constraint Based			Event Hours	
No.	Constraint	Type	Location	Day-Ahead	Balancing	Total	Day-Ahead	Balancing	Total	Day-Ahead	Real-Time
1	Monroe - Vineland	Line	AECO	$6.5	($2.2)	$4.2	$1.8	($0.1)	$1.7	2,858	500
2	AEP - DOM	Interface	500	$0.3	$0.0	$0.3	$1.3	$0.0	$1.4	720	150
3	Cloverdale	Transformer	AEP	$0.8	$0.2	$1.0	$1.0	$0.0	$1.1	615	99
4	Tanners Creek - Miami Fort	Flowgate	MISO	($0.1)	$0.0	($0.1)	$0.9	$0.0	$0.9	1,511	0
5	5004/5005 Interface	Interface	500	$1.7	$0.2	$1.9	$0.7	$0.0	$0.7	175	47
6	Graceton - Safe Harbor	Line	BGE	($2.9)	($1.5)	($4.4)	$0.6	($0.1)	$0.6	3,361	2,046
7	Gardners - Texas East	Line	Met-Ed	($0.4)	($0.1)	($0.4)	$0.5	$0.0	$0.5	2,788	439
8	Emilie - Falls	Line	PECO	$0.1	$0.0	$0.1	$0.4	$0.0	$0.4	1,593	329
9	Batesville - Hubble	Flowgate	MISO	($0.1)	($0.0)	($0.1)	$0.4	$0.0	$0.4	254	134
10	Lakeview - Greenfield	Line	ATSI	$0.5	$0.1	$0.6	$0.5	($0.1)	$0.4	1,356	352
11	Wescosville	Transformer	PPL	$0.2	$0.0	$0.2	$0.3	$0.0	$0.4	553	172
12	Pleasant View - Ashburn	Line	Dominion	($0.3)	($0.1)	($0.5)	$0.3	$0.0	$0.3	303	33
13	Chambers	Transformer	AECO	$0.3	$0.0	$0.3	$0.3	$0.0	$0.3	381	0
14	Bedington - Black Oak	Interface	500	$0.2	$0.0	$0.2	$0.3	$0.0	$0.3	316	52
15	Cedar Creek - Red Lion	Line	DPL	($0.2)	($0.1)	($0.2)	$0.3	$0.0	$0.3	918	69
16	AP South	Interface	500	$0.1	($0.0)	$0.1	$0.3	($0.0)	$0.3	498	37
17	Maple - Jackson	Line	ATSI	($0.4)	($0.1)	($0.4)	$0.2	($0.0)	$0.2	1,000	155
18	Person - Sedge Hill	Line	Dominion	$0.1	$0.0	$0.1	$0.2	($0.0)	$0.2	814	136
19	East Townada - North Meshoppen	Line	PENELEC	$0.2	$0.0	$0.2	$0.2	$0.0	$0.2	605	0
20	Riverside	Line	BGE	$0.1	$0.0	$0.1	$0.2	($0.0)	$0.2	266	69
	Top 20 Total			$6.7	($3.5)	$3.2	$10.8	($0.1)	$10.6	20,885	4,819
	All Other Constraints			($4.3)	($1.9)	($6.3)	$6.1	($0.7)	$5.3	77,972	18,466
	Total			$2.4	($5.4)	($3.0)	$16.9	($0.9)	$16.0	98,857	23,285

BGE Control Zone

Table 11-31 BGE Control Zone top congestion cost impacts (By facility): 2018

				Congestion Costs (Millions)							
				Area Based			Constraint Based			Event Hours	
No.	Constraint	Type	Location	Day-Ahead	Balancing	Total	Day-Ahead	Balancing	Total	Day-Ahead	Real-Time
1	AEP - DOM	Interface	500	$0.5	$0.6	$1.0	$5.6	$0.2	$5.8	720	150
2	Cloverdale	Transformer	AEP	$1.2	$0.5	$1.7	$4.1	$0.1	$4.2	615	99
3	Graceton - Safe Harbor	Line	BGE	$19.6	($1.4)	$18.2	$3.5	($0.3)	$3.2	3,361	2,046
4	Tanners Creek - Miami Fort	Flowgate	MISO	($0.1)	$0.0	($0.1)	$2.8	$0.0	$2.8	1,511	0
5	5004/5005 Interface	Interface	500	$1.6	$0.3	$2.0	$1.8	$0.1	$1.9	175	47
6	Conastone - Peach Bottom	Line	500	$5.1	($0.7)	$4.4	$1.7	$0.0	$1.8	1,100	422
7	Batesville - Hubble	Flowgate	MISO	($0.1)	($0.0)	($0.1)	$1.3	$0.1	$1.4	254	134
8	Bedington - Black Oak	Interface	500	$0.9	$0.2	$1.0	$1.2	$0.0	$1.2	316	52
9	Conastone - Northwest	Line	BGE	$4.7	($0.8)	$3.9	$1.2	$0.0	$1.2	336	234
10	AP South	Interface	500	$0.7	($0.0)	$0.7	$1.1	($0.0)	$1.1	498	37
11	BCPEP	Interface	Pepco	$0.8	$0.0	$0.8	$1.0	$0.0	$1.0	126	0
12	Lakeview - Greenfield	Line	ATSI	$1.4	$0.3	$1.7	$1.4	($0.4)	$1.0	1,356	352
13	Pleasant View - Ashburn	Line	Dominion	($2.3)	($0.0)	($2.3)	$0.9	$0.0	$0.9	303	33
14	Gardners - Texas East	Line	Met-Ed	($0.7)	$0.2	($0.5)	$0.9	$0.0	$0.9	2,788	439
15	Nottingham	Other	PECO	$3.2	$0.0	$3.2	$0.9	$0.0	$0.9	1,157	390
16	Bagley - Graceton	Line	BGE	$3.5	$0.0	$3.6	$0.8	($0.0)	$0.7	595	214
17	Person - Sedge Hill	Line	Dominion	$0.7	$0.0	$0.7	$0.7	($0.0)	$0.7	814	136
18	Maple - Jackson	Line	ATSI	($1.3)	$0.1	($1.2)	$0.7	($0.0)	$0.7	1,000	155
19	Northport - Albion	Flowgate	MISO	$0.1	$0.0	$0.1	$0.5	$0.1	$0.6	132	28
20	Brokaw - Leroy	Flowgate	MISO	$0.4	$0.0	$0.5	$0.4	$0.2	$0.6	1,232	261
	Top 20 Total			$39.8	($0.7)	$39.1	$32.5	$0.1	$32.6	18,389	5,229
	All Other Constraints			$17.6	$0.1	$17.7	$15.6	($2.3)	$13.3	77,235	17,986
	Total			$57.5	($0.7)	$56.8	$48.1	($2.2)	$45.9	95,624	23,215

DPL Control Zone

Table 11-32 DPL Control Zone top congestion cost impacts (By facility): 2018

				Congestion Costs (Millions)							
				Area Based			Constraint Based			Event Hours	
No.	Constraint	Type	Location	Day-Ahead	Balancing	Total	Day-Ahead	Balancing	Total	Day-Ahead	Real-Time
1	North Salisbury - Rockawalkin	Line	DPL	$20.7	$0.0	$20.7	$19.8	$0.0	$19.8	1,610	0
2	Cedar Creek - Clayton	Line	DPL	$8.4	($0.2)	$8.2	$7.9	($0.0)	$7.9	876	39
3	Loretto - Vienna	Line	DPL	$6.2	$0.1	$6.3	$6.3	$0.0	$6.3	936	5
4	Cedar Creek - Red Lion	Line	DPL	$13.8	$0.6	$14.4	$4.5	$0.1	$4.6	918	69
5	Kent - Vaughn	Line	DPL	$3.7	($0.5)	$3.3	$3.8	($0.0)	$3.8	504	57
6	Preston - Tanyard	Line	DPL	$3.5	$0.0	$3.6	$3.6	$0.0	$3.6	918	11
7	AEP - DOM	Interface	500	$1.2	($0.5)	$0.7	$3.3	$0.1	$3.4	720	150
8	Cloverdale	Transformer	AEP	$3.6	($1.0)	$2.6	$2.5	$0.0	$2.5	615	99
9	Dupont Seaford - Laurel	Line	DPL	$2.9	$0.0	$2.9	$2.0	$0.0	$2.0	259	0
10	North Salisbury - Pemberton	Line	DPL	$2.2	($0.3)	$1.9	$2.2	($0.3)	$1.9	469	109
11	Tanners Creek - Miami Fort	Flowgate	MISO	($0.3)	$0.0	($0.3)	$1.7	$0.0	$1.7	1,511	0
12	5004/5005 Interface	Interface	500	$5.9	($0.4)	$5.5	$1.6	$0.1	$1.7	175	47
13	Church - New Meredith	Line	DPL	$1.4	$0.0	$1.4	$1.4	$0.0	$1.4	301	0
14	Gardners - Texas East	Line	Met-Ed	($2.1)	$0.3	($1.8)	$1.1	$0.0	$1.1	2,788	439
15	Graceton - Safe Harbor	Line	BGE	($13.6)	$3.0	($10.7)	$1.2	($0.1)	$1.1	3,361	2,046
16	Easton - Emuni	Line	DPL	$0.9	($0.0)	$0.9	$0.9	($0.0)	$0.9	3,831	2
17	Lakeview - Greenfield	Line	ATSI	$2.2	($0.7)	$1.6	$1.2	($0.3)	$0.9	1,356	352
18	Batesville - Hubble	Flowgate	MISO	($0.2)	$0.0	($0.2)	$0.8	$0.1	$0.9	254	134
19	Easton	Transformer	DPL	$0.9	$0.0	$0.9	$0.9	$0.0	$0.9	101	14
20	Emilie - Falls	Line	PECO	($1.1)	$0.3	($0.8)	$0.9	$0.0	$0.9	1,593	329
	Top 20 Total			$60.3	$0.7	$61.0	$67.7	($0.3)	$67.4	23,096	3,902
	All Other Constraints			($6.1)	($10.2)	($16.3)	$20.2	($2.0)	$18.2	75,708	19,383
	Total			$54.2	($9.5)	$44.7	$87.8	($2.3)	$85.5	98,804	23,285

JCPL Control Zone

Table 11-33 JCPL Control Zone top congestion cost impacts (By facility): 2018

				Congestion Costs (Millions)							
				Area Based			Constraint Based			Event Hours	
No.	Constraint	Type	Location	Day-Ahead	Balancing	Total	Day-Ahead	Balancing	Total	Day-Ahead	Real-Time
1	AEP - DOM	Interface	500	$1.5	($0.2)	$1.3	$3.0	$0.1	$3.2	720	150
2	Cloverdale	Transformer	AEP	$3.9	($1.1)	$2.8	$2.4	$0.0	$2.5	615	99
3	Tanners Creek - Miami Fort	Flowgate	MISO	($0.3)	$0.0	($0.3)	$2.0	$0.0	$2.0	1,511	0
4	5004/5005 Interface	Interface	500	$6.8	($1.3)	$5.4	$1.6	$0.1	$1.7	175	47
5	Emilie - Falls	Line	PECO	$1.3	$0.2	$1.5	$1.5	$0.0	$1.5	1,593	329
6	Northwood	Transformer	Met-Ed	$1.3	$0.1	$1.4	$1.4	($0.0)	$1.4	64	15
7	Monroe - Vineland	Line	AECO	$0.3	$0.1	$0.4	$1.5	($0.1)	$1.4	2,858	500
8	Graceton - Safe Harbor	Line	BGE	($1.9)	($3.4)	($5.3)	$1.4	($0.1)	$1.3	3,361	2,046
9	Gardners - Texas East	Line	Met-Ed	($0.7)	($0.3)	($1.0)	$1.2	$0.0	$1.3	2,788	439
10	Northwood - Northwood Tap	Line	Met-Ed	$1.0	($0.4)	$0.6	$1.2	($0.2)	$1.0	56	72
11	Batesville - Hubble	Flowgate	MISO	($0.2)	$0.0	($0.2)	$0.9	$0.0	$1.0	254	134
12	Wescosville	Transformer	PPL	$1.2	$0.3	$1.5	$0.9	$0.0	$1.0	553	172
13	Lakeview - Greenfield	Line	ATSI	$2.2	($0.7)	$1.5	$1.2	($0.3)	$0.9	1,356	352
14	North Meshoppen	Transformer	PENELEC	$1.2	($0.1)	$1.1	$0.9	$0.0	$0.9	378	71
15	Pleasant View - Ashburn	Line	Dominion	($0.5)	($0.2)	($0.7)	$0.7	$0.0	$0.7	303	33
16	Middletown Jct	Transformer	Met-Ed	($0.4)	$0.0	($0.4)	$0.6	$0.0	$0.6	720	0
17	Bedington - Black Oak	Interface	500	$0.6	($0.1)	$0.5	$0.6	$0.0	$0.6	316	52
18	Cedar Creek - Red Lion	Line	DPL	($0.2)	($0.0)	($0.2)	$0.6	$0.0	$0.6	918	69
19	AP South	Interface	500	$0.2	($0.0)	$0.2	$0.6	($0.0)	$0.6	498	37
20	Maple - Jackson	Line	ATSI	($0.3)	($0.3)	($0.6)	$0.5	($0.0)	$0.5	1,000	155
	Top 20 Total			$16.8	($7.4)	$9.4	$24.9	($0.3)	$24.6	20,037	4,772
	All Other Constraints			$2.6	($7.1)	($4.4)	$14.3	($1.4)	$12.9	78,851	18,513
	Total			$19.4	($14.4)	$5.0	$39.2	($1.7)	$37.5	98,888	23,285

Met-Ed Control Zone

Table 11-34 Met-Ed Control Zone top congestion cost impacts (By facility): 2018

				Congestion Costs (Millions)							
				Area Based			Constraint Based			Event Hours	
No.	Constraint	Type	Location	Day-Ahead	Balancing	Total	Day-Ahead	Balancing	Total	Day-Ahead	Real-Time
1	Middletown Jct	Transformer	Met-Ed	$7.3	$0.0	$7.3	$2.5	$0.0	$2.5	720	0
2	AEP - DOM	Interface	500	$0.2	($0.2)	($0.0)	$2.3	$0.1	$2.4	720	150
3	Gardners - Texas East	Line	Met-Ed	$10.7	($0.4)	$10.3	$2.1	($0.0)	$2.0	2,788	439
4	Hunterstown	Transformer	500	$1.9	$0.0	$1.9	$1.9	$0.0	$1.9	169	367
5	Cloverdale	Transformer	AEP	$0.2	($0.6)	($0.4)	$1.8	$0.0	$1.8	615	99
6	Tanners Creek - Miami Fort	Flowgate	MISO	$0.0	$0.0	$0.0	$1.3	$0.0	$1.3	1,511	0
7	5004/5005 Interface	Interface	500	($0.3)	($0.5)	($0.8)	$1.1	$0.0	$1.2	175	47
8	Ironwood - South Lebanon	Line	Met-Ed	$1.0	($0.2)	$0.9	$1.0	($0.1)	$1.0	238	212
9	Graceton - Safe Harbor	Line	BGE	$1.5	$0.6	$2.1	$0.8	($0.1)	$0.8	3,361	2,046
10	Lakeview - Greenfield	Line	ATSI	($0.2)	($0.5)	($0.6)	$0.9	($0.2)	$0.7	1,356	352
11	Batesville - Hubble	Flowgate	MISO	$0.0	$0.0	$0.0	$0.6	$0.0	$0.6	254	134
12	Northwood	Transformer	Met-Ed	$1.1	($0.1)	$1.0	$0.6	($0.0)	$0.6	64	15
13	Wescosville	Transformer	PPL	$0.6	($0.0)	$0.6	$0.6	$0.0	$0.6	553	172
14	Emilie - Falls	Line	PECO	$0.2	($0.0)	$0.2	$0.6	$0.0	$0.6	1,593	329
15	Bedington - Black Oak	Interface	500	$0.1	($0.0)	$0.1	$0.5	$0.0	$0.5	316	52
16	Pleasant View - Ashburn	Line	Dominion	$0.6	($0.1)	$0.6	$0.5	$0.0	$0.5	303	33
17	AP South	Interface	500	($0.0)	$0.0	($0.0)	$0.4	($0.0)	$0.4	498	37
18	Northwood - Northwood Tap	Line	Met-Ed	$0.8	($1.0)	($0.1)	$0.5	($0.1)	$0.4	56	72
19	Conastone - Peach Bottom	Line	500	$0.1	($0.1)	($0.1)	$0.4	$0.0	$0.4	1,100	422
20	Hunterstown	Transformer	Met-Ed	$0.2	($0.5)	($0.3)	$0.1	($0.5)	($0.4)	169	367
	Top 20 Total			$26.1	($3.6)	$22.5	$20.7	($0.7)	$19.9	16,559	5,345
	All Other Constraints			$11.5	($2.2)	$9.3	$10.9	($0.9)	$10.0	81,866	18,237
	Total			$37.6	($5.7)	$31.8	$31.6	($1.6)	$29.9	98,425	23,582

PECO Control Zone

Table 11-35 PECO Control Zone top congestion cost impacts (By facility): 2018

				Congestion Costs (Millions)							
				Area Based			Constraint Based			Event Hours	
No.	Constraint	Type	Location	Day-Ahead	Balancing	Total	Day-Ahead	Balancing	Total	Day-Ahead	Real-Time
1	AEP - DOM	Interface	500	($1.1)	$0.6	($0.4)	$5.9	$0.2	$6.1	720	150
2	Cloverdale	Transformer	AEP	($3.2)	$1.5	($1.8)	$4.6	$0.1	$4.7	615	99
3	Tanners Creek - Miami Fort	Flowgate	MISO	$0.3	$0.0	$0.3	$3.5	$0.0	$3.5	1,511	0
4	5004/5005 Interface	Interface	500	($3.5)	$0.1	($3.4)	$3.0	$0.1	$3.1	175	47
5	Gardners - Texas East	Line	Met-Ed	$4.0	($0.1)	$3.9	$2.5	$0.1	$2.5	2,788	439
6	Graceton - Safe Harbor	Line	BGE	$37.7	($0.4)	$37.3	$2.7	($0.2)	$2.5	3,361	2,046
7	Emilie - Falls	Line	PECO	$3.2	($0.5)	$2.6	$1.8	$0.0	$1.9	1,593	329
8	Lakeview - Greenfield	Line	ATSI	($2.6)	$0.5	($2.1)	$2.3	($0.5)	$1.8	1,356	352
9	Batesville - Hubble	Flowgate	MISO	$0.2	($0.0)	$0.2	$1.6	$0.1	$1.7	254	134
10	Wescosville	Transformer	PPL	($0.2)	$0.1	($0.0)	$1.5	$0.1	$1.6	553	172
11	Pleasant View - Ashburn	Line	Dominion	$2.3	($0.3)	$2.1	$1.2	$0.0	$1.2	303	33
12	Bedington - Black Oak	Interface	500	($1.2)	$0.1	($1.1)	$1.2	$0.0	$1.2	316	52
13	Monroe - Vineland	Line	AECO	$0.0	($0.2)	($0.1)	$1.3	($0.1)	$1.2	2,858	500
14	AP South	Interface	500	($0.8)	($0.0)	($0.8)	$1.1	($0.0)	$1.1	498	37
15	Person - Sedge Hill	Line	Dominion	($1.1)	$0.0	($1.0)	$0.9	($0.0)	$0.8	814	136
16	Maple - Jackson	Line	ATSI	$4.4	($0.1)	$4.4	$0.9	($0.1)	$0.8	1,000	155
17	East Towanda - North Meshoppen	Line	PENELEC	($0.2)	$0.0	($0.2)	$0.8	$0.0	$0.8	605	0
18	Middletown Jct	Transformer	Met-Ed	$1.8	$0.0	$1.8	$0.7	$0.0	$0.7	720	0
19	Roxana - Praxair	Flowgate	MISO	($3.3)	$0.3	($3.0)	($0.4)	($0.3)	($0.7)	1,132	481
20	Northport - Albion	Flowgate	MISO	($0.2)	$0.0	($0.2)	$0.6	$0.1	$0.7	132	28
	Top 20 Total			$36.7	$1.8	$38.5	$37.6	($0.5)	$37.1	21,304	5,190
	All Other Constraints			$66.5	($3.1)	$63.4	$24.8	($2.3)	$22.5	76,740	18,095
	Total			$103.3	($1.3)	$101.9	$62.4	($2.8)	$59.6	98,044	23,285

PENELEC Control Zone

Table 11-36 PENELEC Control Zone top congestion cost impacts (By facility): 2018

				Congestion Costs (Millions)							
				Area Based			Constraint Based			Event Hours	
No.	Constraint	Type	Location	Day-Ahead	Balancing	Total	Day-Ahead	Balancing	Total	Day-Ahead	Real-Time
1	AEP - DOM	Interface	500	$1.3	($0.2)	$1.0	$2.3	$0.1	$2.3	720	150
2	Cloverdale	Transformer	AEP	($3.0)	($0.1)	($3.0)	$1.6	$0.0	$1.6	615	99
3	Tanners Creek - Miami Fort	Flowgate	MISO	$0.5	$0.0	$0.5	$1.4	$0.0	$1.4	1,511	0
4	Titusville - Union City	Line	PENELEC	$2.2	$0.1	$2.3	$1.3	($0.0)	$1.3	302	76
5	Graceton - Safe Harbor	Line	BGE	$9.4	($0.2)	$9.2	$1.4	($0.1)	$1.3	3,361	2,046
6	Gardners - Texas East	Line	Met-Ed	$4.7	$0.5	$5.2	$1.2	$0.0	$1.2	2,788	439
7	Niles Valley - Sabinsville	Line	PENELEC	$0.0	($1.1)	($1.1)	$0.0	($1.1)	($1.1)	0	112
8	Lakeview - Greenfield	Line	ATSI	($5.4)	($0.3)	($5.7)	$1.1	($0.2)	$0.8	1,356	352
9	Middletown Jct	Transformer	Met-Ed	$0.4	$0.0	$0.4	$0.8	$0.0	$0.8	720	0
10	Asylum	Transformer	PENELEC	$0.7	$0.0	$0.7	$0.7	$0.0	$0.7	381	0
11	Batesville - Hubble	Flowgate	MISO	$0.4	$0.0	$0.4	$0.7	$0.0	$0.7	254	134
12	Wescosville	Transformer	PPL	$1.3	($0.2)	$1.1	$0.7	$0.0	$0.7	553	172
13	North Meshoppen	Transformer	PENELEC	$1.3	$0.9	$2.3	$0.6	$0.0	$0.6	378	71
14	5004/5005 Interface	Interface	500	$10.8	$0.5	$11.3	$0.6	$0.0	$0.6	175	47
15	Emilie - Falls	Line	PECO	($0.1)	$0.0	($0.1)	$0.6	$0.0	$0.6	1,593	329
16	Pleasant View - Ashburn	Line	Dominion	$1.4	($0.1)	$1.3	$0.5	$0.0	$0.5	303	33
17	Conastone - Peach Bottom	Line	500	$1.8	$0.2	$2.0	$0.5	$0.0	$0.5	1,100	422
18	Bedington - Black Oak	Interface	500	$2.7	$0.0	$2.7	$0.4	$0.0	$0.4	316	52
19	Roxana - Praxair	Flowgate	MISO	($2.3)	$0.3	($2.0)	($0.3)	($0.1)	($0.4)	1,132	481
20	Nottingham	Other	PECO	$0.6	$0.0	$0.6	$0.4	$0.0	$0.4	1,157	390
	Top 20 Total			$28.7	$0.1	$28.9	$16.4	($1.3)	$15.1	18,715	5,405
	All Other Constraints			$46.7	($2.7)	$44.0	$15.6	($0.9)	$14.8	81,979	17,810
	Total			$75.4	($2.6)	$72.8	$32.1	($2.2)	$29.9	100,694	23,215

Pepco Control Zone

Table 11-37 Pepco Control Zone top congestion cost impacts (By facility): 2018

				Congestion Costs (Millions)							
				Area Based			Constraint Based			Event Hours	
No.	Constraint	Type	Location	Day-Ahead	Balancing	Total	Day-Ahead	Balancing	Total	Day-Ahead	Real-Time
1	AEP - DOM	Interface	500	$5.0	($0.6)	$4.4	$5.5	$0.2	$5.7	720	150
2	Cloverdale	Transformer	AEP	$5.9	$0.6	$6.5	$4.0	$0.1	$4.0	615	99
3	Graceton - Safe Harbor	Line	BGE	$14.8	$1.4	$16.3	$3.3	($0.3)	$3.0	3,361	2,046
4	Tanners Creek - Miami Fort	Flowgate	MISO	($0.3)	$0.0	($0.3)	$2.7	$0.0	$2.7	1,511	0
5	Conastone - Peach Bottom	Line	500	$5.2	$0.3	$5.5	$1.7	$0.0	$1.7	1,100	422
6	5004/5005 Interface	Interface	500	$0.9	$0.1	$1.0	$1.5	$0.1	$1.6	175	47
7	Batesville - Hubble	Flowgate	MISO	($0.2)	$0.0	($0.2)	$1.3	$0.1	$1.4	254	134
8	Bedington - Black Oak	Interface	500	$2.9	$0.1	$3.0	$1.2	$0.0	$1.2	316	52
9	AP South	Interface	500	$2.1	$0.0	$2.2	$1.1	($0.0)	$1.1	498	37
10	Conastone - Northwest	Line	BGE	$2.2	$0.4	$2.7	$1.0	$0.0	$1.0	336	234
11	BCPEP	Interface	Pepco	$1.0	$0.0	$1.0	$1.0	$0.0	$1.0	126	0
12	Pleasant View - Ashburn	Line	Dominion	($2.7)	($0.2)	($2.9)	$0.9	$0.0	$0.9	303	33
13	Nottingham	Other	PECO	$3.1	$0.0	$3.1	$0.8	$0.0	$0.8	1,157	390
14	Person - Sedge Hill	Line	Dominion	$1.4	($0.0)	$1.3	$0.7	($0.0)	$0.7	814	136
15	Maple - Jackson	Line	ATSI	($0.9)	($0.1)	($1.0)	$0.7	($0.0)	$0.7	1,000	155
16	Bagley - Graceton	Line	BGE	$1.7	$0.1	$1.8	$0.6	($0.0)	$0.6	595	214
17	Gardners - Texas East	Line	Met-Ed	$0.2	$0.0	$0.2	$0.6	$0.0	$0.6	2,788	439
18	Northport - Albion	Flowgate	MISO	$0.3	($0.0)	$0.3	$0.5	$0.1	$0.6	132	28
19	Brokaw - Leroy	Flowgate	MISO	$0.8	($0.0)	$0.7	$0.3	$0.2	$0.5	1,232	261
20	Cedar Grove Sub - Roseland	Line	PSEG	($0.4)	($0.1)	($0.4)	$0.5	($0.0)	$0.5	1,368	64
	Top 20 Total			$43.0	$2.0	$45.0	$30.0	$0.4	$30.4	18,401	4,941
	All Other Constraints			$4.8	$1.8	$6.5	$14.6	($2.4)	$12.2	76,732	18,274
	Total			$47.8	$3.8	$51.5	$44.6	($1.9)	$42.6	95,133	23,215

PPL Control Zone

Table 11-38 PPL Control Zone top congestion cost impacts (By facility): 2018

				Congestion Costs (Millions)							
				Area Based			Constraint Based			Event Hours	
No.	Constraint	Type	Location	Day-Ahead	Balancing	Total	Day-Ahead	Balancing	Total	Day-Ahead	Real-Time
1	AEP - DOM	Interface	500	($1.4)	$0.7	($0.7)	$6.5	$0.2	$6.7	720	150
2	Cloverdale	Transformer	AEP	($3.4)	$2.5	($0.8)	$5.1	$0.1	$5.2	615	99
3	5004/5005 Interface	Interface	500	($8.9)	$3.7	($5.1)	$3.4	$0.1	$3.5	175	47
4	Tanners Creek - Miami Fort	Flowgate	MISO	$0.3	$0.0	$0.3	$3.5	$0.0	$3.5	1,511	0
5	Gardners - Texas East	Line	Met-Ed	$1.1	($0.4)	$0.8	$2.8	$0.1	$2.8	2,788	439
6	Wescosville	Transformer	PPL	$15.8	$1.2	$17.0	$2.1	$0.1	$2.2	553	172
7	Graceton - Safe Harbor	Line	BGE	$4.6	($3.2)	$1.3	$2.3	($0.2)	$2.2	3,361	2,046
8	Lakeview - Greenfield	Line	ATSI	($2.6)	$2.5	($0.0)	$2.6	($0.5)	$2.1	1,356	352
9	Batesville - Hubble	Flowgate	MISO	$0.3	($0.0)	$0.2	$1.7	$0.1	$1.8	254	134
10	Emilie - Falls	Line	PECO	($0.8)	$0.1	($0.7)	$1.7	$0.0	$1.8	1,593	329
11	North Meshoppen	Transformer	PENELEC	($2.6)	$0.4	($2.2)	($1.7)	$0.1	($1.7)	378	71
12	Middletown Jct	Transformer	Met-Ed	$0.4	$0.0	$0.4	$1.5	$0.0	$1.5	720	0
13	Northwood	Transformer	Met-Ed	$2.4	($0.1)	$2.3	$1.4	($0.0)	$1.4	64	15
14	Bedington - Black Oak	Interface	500	($0.1)	$0.1	$0.1	$1.3	$0.0	$1.3	316	52
15	Pleasant View - Ashburn	Line	Dominion	$1.4	$0.2	$1.6	$1.2	$0.0	$1.2	303	33
16	AP South	Interface	500	$0.0	$0.0	$0.0	$1.0	($0.0)	$1.0	498	37
17	Northwood - Northwood Tap	Line	Met-Ed	$2.1	($2.8)	($0.8)	$1.2	($0.3)	$0.9	56	72
18	Quarry - Steel City	Line	PPL	$0.9	$0.0	$0.9	$0.9	$0.0	$0.9	126	84
19	Person - Sedge Hill	Line	Dominion	($0.5)	$0.2	($0.3)	$0.9	($0.0)	$0.9	814	136
20	Nottingham	Other	PECO	$3.1	$0.0	$3.1	$0.8	$0.0	$0.8	1,157	390
	Top 20 Total			$12.3	$5.0	$17.4	$40.1	($0.2)	$39.9	17,358	4,658
	All Other Constraints			$32.8	$6.1	$38.9	$29.8	($2.4)	$27.4	83,079	18,711
	Total			$45.1	$11.2	$56.3	$69.9	($2.6)	$67.3	100,437	23,369

PSEG Control Zone

Table 11-39 PSEG Control Zone top congestion cost impacts (By facility): 2018

				Congestion Costs (Millions)							
				Area Based			Constraint Based			Event Hours	
No.	Constraint	Type	Location	Day-Ahead	Balancing	Total	Day-Ahead	Balancing	Total	Day-Ahead	Real-Time
1	AEP - DOM	Interface	500	$0.4	($0.5)	($0.1)	$5.7	$0.2	$5.9	720	150
2	Cloverdale	Transformer	AEP	$1.6	($1.3)	$0.3	$4.6	$0.1	$4.7	615	99
3	Tanners Creek - Miami Fort	Flowgate	MISO	($0.2)	$0.0	($0.2)	$3.7	$0.0	$3.7	1,511	0
4	5004/5005 Interface	Interface	500	$5.3	($1.1)	$4.2	$2.9	$0.1	$3.0	175	47
5	Emilie - Falls	Line	PECO	$7.7	($0.0)	$7.6	$2.8	$0.0	$2.8	1,593	329
6	Graceton - Safe Harbor	Line	BGE	$0.8	$0.2	$1.0	$2.8	($0.2)	$2.5	3,361	2,046
7	Gardners - Texas East	Line	Met-Ed	$0.1	$0.6	$0.7	$2.4	$0.1	$2.4	2,788	439
8	Monroe - Vineland	Line	AECO	($0.1)	($0.1)	($0.1)	$2.2	($0.1)	$2.1	2,858	500
9	Northwood	Transformer	Met-Ed	$1.1	($0.0)	$1.1	$2.0	($0.0)	$2.0	64	15
10	Wescosville	Transformer	PPL	$0.4	($0.4)	$0.0	$1.7	$0.1	$1.8	553	172
11	Batesville - Hubble	Flowgate	MISO	($0.1)	$0.0	($0.1)	$1.7	$0.1	$1.8	254	134
12	Cedar Grove Sub - Roseland	Line	PSEG	$9.1	($0.2)	$8.9	$1.7	($0.1)	$1.7	1,368	64
13	Pleasant View - Ashburn	Line	Dominion	$0.5	$0.1	$0.5	$1.4	$0.0	$1.4	303	33
14	Northwood - Northwood Tap	Line	Met-Ed	$0.9	($0.9)	($0.1)	$1.7	($0.3)	$1.4	56	72
15	Lakeview - Greenfield	Line	ATSI	$0.2	($1.2)	($1.0)	$1.9	($0.5)	$1.4	1,356	352
16	Bedington - Black Oak	Interface	500	($0.0)	($0.1)	($0.1)	$1.2	$0.0	$1.2	316	52
17	Cedar Creek - Red Lion	Line	DPL	$0.2	$0.2	$0.4	$1.1	$0.0	$1.2	918	69
18	AP South	Interface	500	($0.2)	$0.0	($0.2)	$1.0	($0.0)	$1.0	498	37
19	Maple - Jackson	Line	ATSI	($0.0)	$0.3	$0.2	$1.0	($0.1)	$0.9	1,000	155
20	Person - Sedge Hill	Line	Dominion	$0.1	($0.0)	$0.1	$0.9	($0.0)	$0.9	814	136
	Top 20 Total			$27.8	($4.6)	$23.3	$44.4	($0.7)	$43.8	21,121	4,901
	All Other Constraints			$24.8	($1.9)	$22.9	$29.0	($3.3)	$25.6	79,821	18,384
	Total			$52.7	($6.5)	$46.2	$73.4	($4.0)	$69.4	100,942	23,285

RECO Control Zone

Table 11-40 RECO Control Zone top congestion cost impacts (By facility): 2018

				Congestion Costs (Millions)							
				Area Based			Constraint Based			Event Hours	
No.	Constraint	Type	Location	Day-Ahead	Balancing	Total	Day-Ahead	Balancing	Total	Day-Ahead	Real-Time
1	Burns - Corporate Road	Line	RECO	$0.4	$0.0	$0.4	$0.4	$0.0	$0.4	511	0
2	Maywood - Saddlebrook	Line	PSEG	$0.3	($0.7)	($0.3)	($0.0)	($0.2)	($0.2)	417	98
3	Cedar Grove - Jackson Rd	Line	PSEG	$0.1	($0.4)	($0.3)	($0.0)	($0.2)	($0.2)	213	56
4	AEP - DOM	Interface	500	$0.0	($0.0)	$0.0	$0.2	$0.0	$0.2	720	150
5	Cloverdale	Transformer	AEP	$0.2	$0.0	$0.2	$0.1	$0.0	$0.1	615	99
6	Tanners Creek - Miami Fort	Flowgate	MISO	($0.0)	$0.0	($0.0)	$0.1	$0.0	$0.1	1,511	0
7	Emilie - Falls	Line	PECO	$0.3	($0.1)	$0.3	$0.1	$0.0	$0.1	1,593	329
8	5004/5005 Interface	Interface	500	$0.4	$0.0	$0.5	$0.1	$0.0	$0.1	175	47
9	Graceton - Safe Harbor	Line	BGE	($1.0)	($0.4)	($1.4)	$0.1	($0.0)	$0.1	3,361	2,046
10	Northwood	Transformer	Met-Ed	$0.1	$0.0	$0.1	$0.1	($0.0)	$0.1	64	15
11	Gardners - Texas East	Line	Met-Ed	($0.2)	$0.1	($0.1)	$0.1	$0.0	$0.1	2,788	439
12	Cedar Grove Sub - Roseland	Line	PSEG	$0.6	$0.0	$0.7	$0.1	($0.0)	$0.1	1,368	64
13	Northwood - Northwood Tap	Line	Met-Ed	$0.1	$0.0	$0.1	$0.1	($0.0)	$0.1	56	72
14	Batesville - Hubble	Flowgate	MISO	($0.0)	($0.0)	($0.0)	$0.1	$0.0	$0.1	254	134
15	Wescosville	Transformer	PPL	$0.2	($0.2)	$0.1	$0.1	$0.0	$0.1	553	172
16	Pleasant View - Ashburn	Line	Dominion	($0.2)	$0.1	($0.1)	$0.1	$0.0	$0.1	303	33
17	Ramapo (ConEd) - S Mahwah (RECO)	Line	RECO	$0.1	$0.0	$0.1	$0.1	$0.0	$0.1	73	0
18	Cedar Creek - Red Lion	Line	DPL	($0.1)	$0.1	$0.0	$0.0	$0.0	$0.0	918	69
19	Bedington - Black Oak	Interface	500	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	316	52
20	Maple - Jackson	Line	ATSI	($0.3)	$0.0	($0.3)	$0.0	($0.0)	$0.0	1,000	155
	Top 20 Total			$1.1	($1.3)	($0.2)	$1.7	($0.4)	$1.3	16,809	4,030
	All Other Constraints			($2.3)	$0.3	($2.0)	$0.9	($0.2)	$0.8	77,931	18,818
	Total			($1.2)	($1.0)	($2.2)	$2.6	($0.5)	$2.0	94,740	22,848

West Region Congestion-Event Summaries

AEP Control Zone

Table 11-41 AEP Control Zone top congestion cost impacts (By facility): 2018

				Congestion Costs (Millions)							
				Area Based			Constraint Based			Event Hours	
No.	Constraint	Type	Location	Day-Ahead	Balancing	Total	Day-Ahead	Balancing	Total	Day-Ahead	Real-Time
1	AEP - DOM	Interface	500	$94.8	($11.1)	$83.7	$18.9	$0.6	$19.4	720	150
2	Capitol Hill - Chemical	Line	AEP	$17.4	$0.9	$18.2	$15.6	$0.3	$15.9	510	98
3	Cloverdale	Transformer	AEP	$51.7	($4.1)	$47.6	$13.3	$0.2	$13.6	615	99
4	Tanners Creek - Miami Fort	Flowgate	MISO	$27.2	$0.0	$27.2	$11.5	$0.0	$11.5	1,511	0
5	Graceton - Safe Harbor	Line	BGE	($4.3)	$0.5	($3.8)	$12.1	($1.0)	$11.1	3,361	2,046
6	Batesville - Hubble	Flowgate	MISO	$9.9	($0.2)	$9.7	$5.3	$0.3	$5.7	254	134
7	Conastone - Peach Bottom	Line	500	($2.9)	($0.2)	($3.1)	$5.3	$0.1	$5.4	1,100	422
8	Lakeview - Greenfield	Line	ATSI	($0.5)	($2.4)	($2.9)	$6.0	($1.6)	$4.4	1,356	352
9	Pleasant View - Ashburn	Line	Dominion	$0.7	($0.0)	$0.6	$4.0	$0.1	$4.1	303	33
10	5004/5005 Interface	Interface	500	$11.6	($1.1)	$10.5	$3.9	$0.1	$4.0	175	47
11	Delaware - Hogan	Line	AEP	$8.0	($2.6)	$5.4	$4.5	($0.6)	$3.9	1,227	235
12	Bedington - Black Oak	Interface	500	$5.9	($0.5)	$5.4	$3.4	$0.1	$3.5	316	52
13	Nottingham	Other	PECO	($0.7)	$0.0	($0.7)	$3.3	$0.0	$3.3	1,157	390
14	Conastone - Northwest	Line	BGE	($1.0)	($0.0)	($1.0)	$3.0	$0.0	$3.0	336	234
15	AP South	Interface	500	$5.9	($0.1)	$5.9	$3.0	($0.0)	$3.0	498	37
16	Wescosville	Transformer	PPL	$0.4	$0.3	$0.7	$2.7	$0.2	$2.9	553	172
17	Delco Remy - Fall Creek	Line	AEP	$4.7	($1.1)	$3.6	$3.0	($0.2)	$2.7	247	18
18	Maple - Jackson	Line	ATSI	($0.4)	($0.2)	($0.6)	$3.0	($0.2)	$2.7	1,000	155
19	Gable Switch Station - South Cadiz	Line	AEP	$4.1	($0.8)	$3.3	$3.0	($0.2)	$2.7	284	106
20	Tanners Creek - Miami Fort	Line	AEP	$4.1	($1.8)	$2.2	$2.6	$0.1	$2.7	673	489
	Top 20 Total			$236.6	($24.6)	$212.0	$127.4	($1.9)	$125.6	16,196	5,269
	All Other Constraints			$121.7	($12.3)	$109.4	$107.5	($9.3)	$98.2	87,131	17,743
	Total			$358.2	($36.9)	$321.4	$234.9	($11.1)	$223.8	103,327	23,012

APS Control Zone

Table 11-42 APS Control Zone top congestion cost impacts (By facility): 2018

				Congestion Costs (Millions)							
				Area Based			Constraint Based			Event Hours	
No.	Constraint	Type	Location	Day-Ahead	Balancing	Total	Day-Ahead	Balancing	Total	Day-Ahead	Real-Time
1	AEP - DOM	Interface	500	$8.8	$0.5	$9.3	$7.5	$0.3	$7.8	720	150
2	Cloverdale	Transformer	AEP	$7.7	($0.3)	$7.4	$5.1	$0.1	$5.2	615	99
3	Tanners Creek - Miami Fort	Flowgate	MISO	($0.1)	$0.0	($0.1)	$4.4	$0.0	$4.4	1,511	0
4	Graceton - Safe Harbor	Line	BGE	$1.9	($0.9)	$1.0	$4.3	($0.4)	$4.0	3,361	2,046
5	Gardners - Texas East	Line	Met-Ed	$4.8	$0.4	$5.1	$2.1	$0.1	$2.2	2,788	439
6	Batesville - Hubble	Flowgate	MISO	($0.1)	$0.0	($0.1)	$2.0	$0.1	$2.1	254	134
7	Conastone - Peach Bottom	Line	500	$0.9	($0.2)	$0.6	$2.0	$0.1	$2.0	1,100	422
8	Wescosville	Transformer	PPL	($0.2)	($0.1)	($0.3)	$1.8	$0.1	$1.9	553	172
9	5004/5005 Interface	Interface	500	$1.2	($0.2)	$1.0	$1.6	$0.1	$1.7	175	47
10	Pleasant View - Ashburn	Line	Dominion	($1.9)	($0.0)	($1.9)	$1.5	$0.0	$1.5	303	33
11	Bedington - Black Oak	Interface	500	$5.9	$0.5	$6.4	$1.4	$0.0	$1.5	316	52
12	Lakeview - Greenfield	Line	ATSI	$2.0	$0.0	$2.0	$2.1	($0.7)	$1.4	1,356	352
13	Gable Switch Station - South Cadiz	Line	AEP	($0.8)	$0.1	($0.7)	$1.4	($0.1)	$1.3	284	106
14	AP South	Interface	500	$6.2	($0.0)	$6.1	$1.2	($0.0)	$1.2	498	37
15	Nottingham	Other	PECO	$0.4	$0.0	$0.4	$1.2	$0.0	$1.2	1,157	390
16	Capitol Hill - Chemical	Line	AEP	$0.5	$0.1	$0.5	$1.0	$0.1	$1.1	510	98
17	Conastone - Northwest	Line	BGE	$0.4	$0.1	$0.5	$1.1	$0.0	$1.1	336	234
18	Maple - Jackson	Line	ATSI	($0.4)	$0.0	($0.4)	$1.1	($0.1)	$1.1	1,000	155
19	Person - Sedge Hill	Line	Dominion	$1.4	($0.0)	$1.4	$1.0	($0.0)	$1.0	814	136
20	Northport - Albion	Flowgate	MISO	$0.1	($0.0)	$0.1	$0.8	$0.1	$0.9	132	28
	Top 20 Total			$38.5	($0.1)	$38.4	$44.7	($0.1)	$44.5	17,783	5,130
	All Other Constraints			$16.4	($1.0)	$15.4	$35.3	($3.3)	$32.0	80,959	18,087
	Total			$54.9	($1.1)	$53.8	$79.9	($3.4)	$76.5	98,742	23,217

ATSI Control Zone

Table 11-43 ATSI Control Zone top congestion cost impacts (By facility): 2018

				Congestion Costs (Millions)							
				Area Based			Constraint Based			Event Hours	
No.	Constraint	Type	Location	Day-Ahead	Balancing	Total	Day-Ahead	Balancing	Total	Day-Ahead	Real-Time
1	AEP - DOM	Interface	500	($7.3)	($1.2)	($8.5)	$7.2	$0.2	$7.5	720	150
2	Cloverdale	Transformer	AEP	($3.7)	$0.2	($3.5)	$6.3	$0.1	$6.4	615	99
3	Tanners Creek - Miami Fort	Flowgate	MISO	$0.5	$0.0	$0.5	$5.9	$0.0	$5.9	1,511	0
4	Graceton - Safe Harbor	Line	BGE	$3.4	($1.0)	$2.4	$5.3	($0.5)	$4.8	3,361	2,046
5	Lakeview - Greenfield	Line	ATSI	$35.3	($12.2)	$23.0	$4.0	($0.8)	$3.2	1,356	352
6	Batesville - Hubble	Flowgate	MISO	$0.1	($0.1)	$0.0	$2.6	$0.1	$2.7	254	134
7	Conastone - Peach Bottom	Line	500	$2.1	($0.4)	$1.7	$2.6	$0.1	$2.7	1,100	422
8	Wescosville	Transformer	PPL	($1.0)	$0.7	($0.3)	$2.3	$0.1	$2.4	553	172
9	Pleasant View - Ashburn	Line	Dominion	($1.1)	$0.5	($0.6)	$2.3	$0.0	$2.3	303	33
10	Gable Switch Station - South Cadiz	Line	AEP	$4.6	($0.9)	$3.7	$2.4	($0.2)	$2.2	284	106
11	Maple - Jackson	Line	ATSI	$11.2	($0.3)	$10.9	$1.9	($0.1)	$1.8	1,000	155
12	Nottingham	Other	PECO	$1.5	$0.0	$1.5	$1.7	$0.0	$1.7	1,157	390
13	5004/5005 Interface	Interface	500	($3.3)	$0.1	($3.2)	$1.6	$0.1	$1.6	175	47
14	Bedington - Black Oak	Interface	500	($1.9)	($0.0)	($1.9)	$1.5	$0.0	$1.5	316	52
15	Krendale - Shanorma	Line	APS	$8.6	$0.0	$8.6	$1.3	$0.0	$1.3	976	0
16	AP South	Interface	500	($3.1)	$0.1	($3.0)	$1.3	($0.0)	$1.3	498	37
17	Person - Sedge Hill	Line	Dominion	($1.4)	$0.1	($1.3)	$1.3	($0.0)	$1.2	814	136
18	Northport - Albion	Flowgate	MISO	$0.3	$0.1	$0.4	$0.9	$0.2	$1.1	132	28
19	Brokaw - Leroy	Flowgate	MISO	$1.3	($0.1)	$1.2	$0.7	$0.4	$1.1	1,232	261
20	North Salisbury - Rockawalkin	Line	DPL	$0.0	$0.5	$0.5	$0.0	($1.0)	($1.0)	0	784
	Top 20 Total			$46.2	($14.1)	$32.1	$53.1	($1.3)	$51.8	16,357	5,404
	All Other Constraints			$49.9	($6.5)	$43.4	$49.8	($4.2)	$45.6	80,406	17,597
	Total			$96.0	($20.6)	$75.5	$102.9	($5.5)	$97.4	96,763	23,001

ComEd Control Zone

Table 11-44 ComEd Control Zone top congestion cost impacts (By facility): 2018

				Congestion Costs (Millions)							
				Area Based			Constraint Based			Event Hours	
No.	Constraint	Type	Location	Day-Ahead	Balancing	Total	Day-Ahead	Balancing	Total	Day-Ahead	Real-Time
1	AEP - DOM	Interface	500	$8.7	$8.8	$17.5	$9.6	$0.3	$10.0	720	150
2	Cloverdale	Transformer	AEP	$14.5	$1.8	$16.3	$7.9	$0.1	$8.1	615	99
3	Graceton - Safe Harbor	Line	BGE	($5.3)	($2.1)	($7.4)	$8.7	($0.7)	$7.9	3,361	2,046
4	Tanners Creek - Miami Fort	Flowgate	MISO	$8.9	$0.0	$8.9	$7.3	$0.0	$7.3	1,511	0
5	Davis	Transformer	ComEd	$6.4	$0.0	$6.4	$6.4	$0.0	$6.4	443	10
6	Quad Cities - Cordova	Flowgate	MISO	$8.4	$0.0	$8.4	$5.6	$0.0	$5.6	1,522	0
7	Quad Cities	Transformer	ComEd	$5.4	$0.0	$5.4	$5.4	$0.0	$5.4	2,614	0
8	Conastone - Peach Bottom	Line	500	($2.1)	$0.0	($2.1)	$4.2	$0.1	$4.3	1,100	422
9	Lakeview - Greenfield	Line	ATSI	$8.9	$3.6	$12.6	$5.2	($1.0)	$4.1	1,356	352
10	Delaware - Hogan	Line	AEP	$1.3	($0.0)	$1.3	$4.4	($0.4)	$3.9	1,227	235
11	Silver lake	Transformer	ComEd	$3.7	$0.0	$3.7	$3.6	$0.0	$3.6	104	0
12	Batesville - Hubble	Flowgate	MISO	$8.5	$0.8	$9.4	$3.2	$0.1	$3.3	254	134
13	Braidwood - East Frankfort	Line	ComEd	$4.9	($0.2)	$4.8	$3.2	($0.1)	$3.2	203	144
14	Cherry Valley	Transformer	ComEd	$3.1	$0.0	$3.1	$3.1	$0.0	$3.1	403	3
15	5004/5005 Interface	Interface	500	$3.9	$0.4	$4.3	$2.5	$0.1	$2.6	175	47
16	Belvidere - Chrysler Corp.	Line	ComEd	$2.5	$0.0	$2.5	$2.6	$0.0	$2.6	211	0
17	Nottingham	Other	PECO	($1.6)	$0.0	($1.6)	$2.4	$0.0	$2.4	1,157	390
18	Tollway	Transformer	ComEd	$2.3	$0.0	$2.3	$2.4	$0.0	$2.4	208	4
19	Bedington - Black Oak	Interface	500	$2.0	$0.4	$2.4	$2.1	$0.0	$2.2	316	52
20	Tanners Creek - Miami Fort	Line	AEP	$1.6	$3.1	$4.7	$2.2	($0.1)	$2.1	673	489
	Top 20 Total			$86.0	$16.8	$102.8	$92.1	($1.6)	$90.5	18,173	4,577
	All Other Constraints			$102.9	$28.4	$131.3	$80.1	($7.4)	$72.7	85,621	18,434
	Total			$188.9	$45.2	$234.1	$172.3	($9.0)	$163.2	103,794	23,011

DAY Control Zone

Table 11-45 DAY Control Zone top congestion cost impacts (By facility): 2018

				Congestion Costs (Millions)							
				Area Based			Constraint Based			Event Hours	
No.	Constraint	Type	Location	Day-Ahead	Balancing	Total	Day-Ahead	Balancing	Total	Day-Ahead	Real-Time
1	Tanners Creek - Miami Fort	Flowgate	MISO	$5.2	$0.0	$5.2	$1.9	$0.0	$1.9	1,511	0
2	AEP - DOM	Interface	500	($1.0)	($1.4)	($2.3)	$1.8	$0.1	$1.8	720	150
3	Cloverdale	Transformer	AEP	($1.2)	($0.4)	($1.6)	$1.6	$0.0	$1.6	615	99
4	Graceton - Safe Harbor	Line	BGE	$1.9	$0.2	$2.1	$1.6	($0.1)	$1.5	3,361	2,046
5	Batesville - Hubble	Flowgate	MISO	$1.9	$0.6	$2.4	$0.9	$0.0	$0.9	254	134
6	Lakeview - Greenfield	Line	ATSI	($2.4)	($0.6)	($3.0)	$1.0	($0.2)	$0.8	1,356	352
7	Conastone - Peach Bottom	Line	500	$1.4	($0.1)	$1.3	$0.7	$0.0	$0.7	1,100	422
8	Tanners Creek - Miami Fort	Line	AEP	$0.6	$1.4	$2.0	$0.6	($0.0)	$0.5	673	489
9	5004/5005 Interface	Interface	500	($0.8)	$0.0	($0.8)	$0.5	$0.0	$0.5	175	47
10	Nottingham	Other	PECO	$0.8	$0.0	$0.8	$0.5	$0.0	$0.5	1,157	390
11	Terminal	Transformer	DEOK	($0.0)	$0.0	$0.0	$0.4	$0.0	$0.5	322	17
12	Bedington - Black Oak	Interface	500	($0.2)	($0.0)	($0.2)	$0.4	$0.0	$0.4	316	52
13	Conastone - Northwest	Line	BGE	$0.4	$0.1	$0.5	$0.4	($0.0)	$0.4	336	234
14	Pierce	Transformer	DEOK	$0.7	$0.0	$0.7	$0.4	$0.0	$0.4	305	0
15	Maple - Jackson	Line	ATSI	$0.6	($0.1)	$0.5	$0.4	($0.0)	$0.4	1,000	155
16	Delco Remy - Fall Creek	Line	AEP	$0.1	$0.0	$0.1	$0.4	($0.0)	$0.4	247	18
17	AP South	Interface	500	($0.6)	$0.0	($0.6)	$0.4	($0.0)	$0.4	498	37
18	Pleasant View - Ashburn	Line	Dominion	($0.4)	($0.0)	($0.4)	$0.3	$0.0	$0.3	303	33
19	Pierce Duke (DEOK) - Pierce (OVEC)	Line	DEOK	$0.6	($0.0)	$0.6	$0.3	($0.0)	$0.3	285	3
20	Krendale - Shanorma	Line	APS	$1.3	$0.0	$1.3	$0.3	$0.0	$0.3	976	0
	Top 20 Total			$9.0	($0.3)	$8.7	$14.9	($0.3)	$14.7	15,510	4,678
	All Other Constraints			$7.9	($1.5)	$6.3	$13.0	($1.1)	$11.9	85,682	18,334
	Total			$16.8	($1.8)	$15.0	$27.9	($1.4)	$26.5	101,192	23,012

DEOK Control Zone

Table 11-46 DEOK Control Zone top congestion cost impacts (By facility): 2018

				Congestion Costs (Millions)							
				Area Based			Constraint Based			Event Hours	
No.	Constraint	Type	Location	Day-Ahead	Balancing	Total	Day-Ahead	Balancing	Total	Day-Ahead	Real-Time
1	Tanners Creek - Miami Fort	Flowgate	MISO	$29.5	$0.0	$29.5	$3.8	$0.0	$3.8	1,511	0
2	AEP - DOM	Interface	500	($4.8)	($4.4)	($9.2)	$2.8	$0.1	$2.9	720	150
3	Cloverdale	Transformer	AEP	($5.0)	($0.4)	($5.4)	$2.4	$0.0	$2.5	615	99
4	Graceton - Safe Harbor	Line	BGE	$3.6	($0.8)	$2.8	$2.6	($0.2)	$2.3	3,361	2,046
5	Batesville - Hubble	Flowgate	MISO	$21.2	$0.4	$21.7	$1.9	$0.1	$1.9	254	134
6	Terminal	Transformer	DEOK	$3.6	$0.0	$3.7	$1.6	$0.0	$1.6	322	17
7	East Bend	Transformer	DEOK	$1.5	$0.0	$1.5	$1.5	$0.0	$1.5	453	0
8	Pierce	Transformer	DEOK	$4.9	$0.0	$4.9	$1.4	$0.0	$1.4	305	0
9	Delaware - Hogan	Line	AEP	$1.2	($0.5)	$0.7	$1.4	($0.1)	$1.3	1,227	235
10	Lakeview - Greenfield	Line	ATSI	($2.5)	($0.9)	($3.4)	$1.6	($0.3)	$1.3	1,356	352
11	Conastone - Peach Bottom	Line	500	$1.5	($0.4)	$1.1	$1.2	$0.0	$1.2	1,100	422
12	Pierce Duke (DEOK) - Pierce (OVEC)	Line	DEOK	$4.1	($0.0)	$4.1	$1.2	($0.0)	$1.2	285	3
13	Pierce - Beckjord	Flowgate	MISO	$4.7	$0.0	$4.7	$1.0	$0.0	$1.0	263	0
14	Tanners Creek - Miami Fort	Line	AEP	$2.3	($0.2)	$2.1	$1.0	($0.0)	$1.0	673	489
15	5004/5005 Interface	Interface	500	($1.5)	($0.2)	($1.8)	$0.8	$0.0	$0.8	175	47
16	Nottingham	Other	PECO	$0.8	$0.0	$0.8	$0.7	$0.0	$0.7	1,157	390
17	Miami Fort	Transformer	DEOK	$0.9	($0.0)	$0.8	$0.7	($0.0)	$0.7	317	2
18	Bedington - Black Oak	Interface	500	($0.7)	($0.2)	($0.9)	$0.7	$0.0	$0.7	316	52
19	Conastone - Northwest	Line	BGE	$0.5	($0.3)	$0.2	$0.6	($0.0)	$0.6	336	234
20	Hazard	Transformer	AEP	($0.2)	($0.0)	($0.2)	$0.6	$0.0	$0.6	246	17
	Top 20 Total			$65.6	($7.9)	$57.7	$29.4	($0.4)	$29.0	14,992	4,689
	All Other Constraints			$11.6	($2.3)	$9.4	$21.4	($1.7)	$19.7	80,408	18,305
	Total			$77.2	($10.1)	$67.1	$50.8	($2.1)	$48.7	95,400	22,994

DLCO Control Zone

Table 11-47 DLCO Control Zone top congestion cost impacts (By facility): 2018

				Congestion Costs (Millions)							
				Area Based			Constraint Based			Event Hours	
No.	Constraint	Type	Location	Day-Ahead	Balancing	Total	Day-Ahead	Balancing	Total	Day-Ahead	Real-Time
1	AEP - DOM	Interface	500	$1.9	($0.6)	$1.3	$1.5	$0.0	$1.6	720	150
2	Cloverdale	Transformer	AEP	$0.8	($0.1)	$0.7	$1.3	$0.0	$1.4	615	99
3	Tanners Creek - Miami Fort	Flowgate	MISO	$0.1	$0.0	$0.1	$1.2	$0.0	$1.2	1,511	0
4	Lakeview - Greenfield	Line	ATSI	($2.7)	$1.0	($1.7)	$0.8	($0.2)	$0.6	1,356	352
5	Graceton - Safe Harbor	Line	BGE	$0.0	($0.2)	($0.1)	$0.7	($0.1)	$0.6	3,361	2,046
6	Conastone - Peach Bottom	Line	500	$0.1	($0.1)	($0.0)	$0.6	$0.0	$0.6	1,100	422
7	Batesville - Hubble	Flowgate	MISO	$0.0	($0.0)	$0.0	$0.5	$0.0	$0.6	254	134
8	Pleasant View - Ashburn	Line	Dominion	($0.0)	$0.1	$0.0	$0.5	$0.0	$0.5	303	33
9	Wescosville	Transformer	PPL	($0.1)	$0.1	$0.0	$0.4	$0.0	$0.5	553	172
10	Gable Switch Station - South Cadiz	Line	AEP	($0.2)	$0.0	($0.2)	$0.4	($0.0)	$0.4	284	106
11	Maple - Jackson	Line	ATSI	($1.4)	($0.2)	($1.5)	$0.4	($0.0)	$0.4	1,000	155
12	Nottingham	Other	PECO	$0.1	$0.0	$0.1	$0.3	$0.0	$0.3	1,157	390
13	Bedington - Black Oak	Interface	500	$0.5	($0.1)	$0.4	$0.3	$0.0	$0.3	316	52
14	5004/5005 Interface	Interface	500	$1.2	($0.1)	$1.1	$0.3	$0.0	$0.3	175	47
15	Person - Sedge Hill	Line	Dominion	$0.1	($0.0)	$0.1	$0.3	($0.0)	$0.3	814	136
16	Krendale - Shanorma	Line	APS	($0.4)	$0.0	($0.4)	$0.3	$0.0	$0.3	976	0
17	Brunot Island - Collier	Line	DLCO	$1.0	$0.0	$1.0	$0.2	$0.0	$0.3	208	2
18	AP South	Interface	500	$0.3	$0.0	$0.3	$0.2	($0.0)	$0.2	498	37
19	Northport - Albion	Flowgate	MISO	($0.1)	$0.0	($0.1)	$0.2	$0.0	$0.2	132	28
20	Yukon	Transformer	500	$0.4	$0.3	$0.7	$0.2	($0.0)	$0.2	102	58
	Top 20 Total			$1.6	$0.3	$1.9	$10.8	($0.2)	$10.6	15,435	4,419
	All Other Constraints			$4.2	$1.2	$5.4	$6.5	($1.0)	$5.5	75,063	18,411
	Total			$5.8	$1.6	$7.4	$17.3	($1.1)	$16.2	90,498	22,830

EKPC Control Zone

Table 11-48 EKPC Control Zone top congestion cost impacts (By facility): 2018

				Congestion Costs (Millions)							
				Area Based			Constraint Based			Event Hours	
No.	Constraint	Type	Location	Day-Ahead	Balancing	Total	Day-Ahead	Balancing	Total	Day-Ahead	Real-Time
1	AEP - DOM	Interface	500	$1.5	$1.2	$2.7	$2.4	$0.1	$2.5	720	150
2	Cloverdale	Transformer	AEP	($2.8)	$0.3	($2.4)	$1.5	$0.0	$1.5	615	99
3	Tanners Creek - Miami Fort	Flowgate	MISO	($2.7)	$0.0	($2.7)	$1.5	$0.0	$1.5	1,511	0
4	Graceton - Safe Harbor	Line	BGE	$1.0	$0.4	$1.4	$1.2	($0.1)	$1.1	3,361	2,046
5	Delco Remy - Fall Creek	Line	AEP	($0.3)	$0.1	($0.3)	$0.9	($0.0)	$0.9	247	18
6	Lakeview - Greenfield	Line	ATSI	($0.9)	$0.4	($0.4)	$1.0	($0.2)	$0.8	1,356	352
7	Conastone - Peach Bottom	Line	500	$0.3	$0.1	$0.4	$0.6	$0.0	$0.6	1,100	422
8	Batesville - Hubble	Flowgate	MISO	($11.0)	$0.2	($10.8)	$0.5	$0.0	$0.5	254	134
9	5004/5005 Interface	Interface	500	($0.5)	$0.1	($0.4)	$0.5	$0.0	$0.5	175	47
10	Tanners Creek - Miami Fort	Line	AEP	($0.2)	($0.0)	($0.2)	$0.5	$0.0	$0.5	673	489
11	Bedington - Black Oak	Interface	500	($0.2)	$0.1	($0.1)	$0.4	$0.0	$0.5	316	52
12	AP South	Interface	500	($0.1)	$0.0	($0.1)	$0.4	($0.0)	$0.4	498	37
13	Hazard	Transformer	AEP	($0.4)	$0.3	($0.1)	$0.3	$0.0	$0.4	246	17
14	Broadford - Saltville	Line	AEP	$0.3	($0.3)	$0.1	$0.3	$0.0	$0.4	355	56
15	Northport - Albion	Flowgate	MISO	$0.1	$0.0	$0.1	$0.3	$0.1	$0.3	132	28
16	Conastone - Northwest	Line	BGE	$0.2	$0.0	$0.2	$0.3	$0.0	$0.3	336	234
17	Nottingham	Other	PECO	$0.3	$0.0	$0.3	$0.3	$0.0	$0.3	1,157	390
18	Terminal	Transformer	DEOK	($0.1)	$0.0	($0.1)	$0.3	$0.0	$0.3	322	17
19	Brokaw - Leroy	Flowgate	MISO	$0.4	($0.1)	$0.3	$0.2	$0.1	$0.3	1,232	261
20	Pleasant View - Ashburn	Line	Dominion	($0.0)	($0.1)	($0.1)	$0.2	$0.0	$0.3	303	33
	Top 20 Total			($15.2)	$2.9	($12.3)	$13.8	$0.1	$13.9	14,909	4,882
	All Other Constraints			($1.8)	$1.7	($0.1)	$10.2	($0.8)	$9.5	79,518	18,112
	Total			($17.0)	$4.6	($12.4)	$24.0	($0.7)	$23.4	94,427	22,994

OVEC Control Zone

Table 11-49 OVEC Control Zone top congestion cost impacts (By facility): December, 2018[25]

				Congestion Costs (Millions)							
				Area Based			Constraint Based			Event Hours	
No.	Constraint	Type	Location	Day-Ahead	Balancing	Total	Day-Ahead	Balancing	Total	Day-Ahead	Real-Time
1	Cedar Grove - Jackson Rd	Line	PSEG	($0.0)	$0.1	$0.0	($0.0)	$0.0	$0.0	213	56
2	Maywood - Saddlebrook	Line	PSEG	($0.0)	$0.0	($0.0)	($0.0)	$0.0	($0.0)	417	98
3	Unclassified	Unclassified	Unclassified	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	0	0
4	College Corner - Richmond	Line	AEP	$0.0	($0.0)	($0.0)	$0.0	($0.0)	($0.0)	18	73
5	Dupnt Seaford - Laurel	Line	DPL	$0.0	($0.1)	($0.1)	$0.0	($0.0)	($0.0)	0	156
6	Segreto - Palisades	Flowgate	MISO	$0.3	($0.1)	$0.2	$0.0	($0.0)	($0.0)	441	117
7	Monroe - Vineland	Line	AECO	$0.0	($0.0)	($0.0)	$0.0	($0.0)	($0.0)	2,858	500
8	New Meredith - Church	Line	DPL	$0.0	($0.0)	($0.0)	$0.0	($0.0)	($0.0)	0	79
9	Maroa - E GooseCreek	Flowgate	MISO	($0.1)	$0.0	($0.1)	$0.0	($0.0)	($0.0)	287	96
10	Burnham - Munster	Line	ComEd	$0.0	$0.0	$0.0	$0.0	($0.0)	($0.0)	0	129
11	Big Pine Substation - Kiski Valley	Line	APS	$0.0	($0.1)	($0.1)	$0.0	$0.0	$0.0	251	80
12	Homer City	Transformer	PENELEC	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	39	9
13	Kent - Vaughn	Line	DPL	$0.0	($0.1)	($0.1)	$0.0	($0.0)	($0.0)	504	57
14	Sandburg	Flowgate	MISO	($0.0)	$0.0	($0.0)	$0.0	($0.0)	($0.0)	74	66
15	Fargo	Flowgate	MISO	$0.0	($0.0)	$0.0	$0.0	($0.0)	($0.0)	1,308	510
16	Marblehead	Flowgate	MISO	$0.0	($0.0)	($0.0)	$0.0	($0.0)	($0.0)	411	484
17	Farilawn - Waldwick	Line	PSEG	$0.0	($0.0)	($0.0)	$0.0	($0.0)	($0.0)	11	18
18	West Akron - Brush	Line	ATSI	$0.0	($0.1)	($0.0)	$0.0	($0.0)	($0.0)	241	36
19	Carlisle Pike - Gardners	Line	PENELEC	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	356	14
20	North Champaign - Vermilion	Flowgate	MISO	$0.0	$0.0	$0.0	$0.0	($0.0)	($0.0)	63	28
	Top 20 Total			$0.2	($0.4)	($0.1)	($0.0)	$0.0	$0.0	7,492	2,606
	All Other Constraints			$0.2	$0.2	$0.3	$0.0	($0.0)	($0.0)	35,074	8,662
	Total			$0.4	($0.2)	$0.2	($0.0)	$0.0	$0.0	42,566	11,268

25 In December 2018, PJM integrated the Ohio Valley Electric Corporation (OVEC.)

South Region Congestion-Event Summaries

Dominion Control Zone

Table 11-50 Dominion Control Zone top congestion cost impacts (By facility): 2018

				Congestion Costs (Millions)							
				Area Based			Constraint Based			Event Hours	
No.	Constraint	Type	Location	Day-Ahead	Balancing	Total	Day-Ahead	Balancing	Total	Day-Ahead	Real-Time
1	AEP - DOM	Interface	500	$11.9	($2.3)	$9.6	$23.9	$0.7	$24.6	720	150
2	Cloverdale	Transformer	AEP	$11.5	$1.1	$12.6	$14.5	$0.3	$14.7	615	99
3	Tanners Creek - Miami Fort	Flowgate	MISO	($0.2)	$0.0	($0.2)	$9.2	$0.0	$9.2	1,511	0
4	Graceton - Safe Harbor	Line	BGE	$8.7	($2.2)	$6.5	$10.1	($0.9)	$9.2	3,361	2,046
5	Pleasant View - Ashburn	Line	Dominion	$29.1	$1.1	$30.2	$6.2	$0.1	$6.4	303	33
6	Conastone - Peach Bottom	Line	500	$0.3	$0.0	$0.3	$5.0	$0.1	$5.1	1,100	422
7	Batesville - Hubble	Flowgate	MISO	($0.1)	$0.1	$0.0	$4.5	$0.4	$4.9	254	134
8	5004/5005 Interface	Interface	500	$0.8	$0.1	$1.0	$4.5	$0.1	$4.6	175	47
9	AP South	Interface	500	$6.7	($0.1)	$6.6	$4.1	($0.0)	$4.1	498	37
10	Bedington - Black Oak	Interface	500	$4.3	($0.2)	$4.1	$4.0	$0.1	$4.1	316	52
11	Gardners - Texas East	Line	Met-Ed	$0.3	($0.1)	$0.3	$3.2	$0.1	$3.3	2,788	439
12	Conastone - Northwest	Line	BGE	$0.6	$0.3	$0.8	$3.0	$0.0	$3.0	336	234
13	Person - Sedge Hill	Line	Dominion	$5.6	($0.4)	$5.1	$2.7	($0.1)	$2.7	814	136
14	Nottingham	Other	PECO	$1.5	$0.0	$1.5	$2.6	$0.0	$2.6	1,157	390
15	Northport - Albion	Flowgate	MISO	$0.2	($0.0)	$0.2	$1.9	$0.3	$2.2	132	28
16	Maple - Jackson	Line	ATSI	($0.7)	$0.1	($0.6)	$2.4	($0.1)	$2.2	1,000	155
17	Brokaw - Leroy	Flowgate	MISO	$0.5	($0.2)	$0.4	$1.2	$0.7	$1.9	1,232	261
18	Broadford - Saltville	Line	AEP	($0.1)	$0.1	$0.1	$1.8	$0.0	$1.9	355	56
19	Bagley - Graceton	Line	BGE	$0.2	($0.2)	($0.0)	$1.8	($0.1)	$1.8	595	214
20	Wescosville	Transformer	PPL	$0.1	$0.1	$0.2	$1.6	$0.2	$1.7	553	172
	Top 20 Total			$81.2	($2.6)	$78.7	$108.2	$2.1	$110.3	17,815	5,105
	All Other Constraints			$24.2	($0.4)	$23.9	$50.7	($8.8)	$41.8	80,388	18,112
	Total			$105.5	($2.9)	$102.5	$158.9	($6.8)	$152.1	98,203	23,217

Congestion Event Summary for MISO Flowgates

PJM and MISO have a joint operating agreement (JOA) which defines a coordinated method for congestion management. This agreement establishes reciprocal, coordinated flowgates in the combined footprint whose operating limits are respected by the operators of both organizations.[26] A flowgate is a facility or group of facilities that may act as constraint points on the regional system.[27] PJM models these coordinated flowgates and controls for them in its security-constrained, economic dispatch.

As of December 31, 2018, PJM had 137 flowgates eligible for M2M (Market to Market) coordination and MISO had 239 flowgates eligible for M2M coordination.

Table 11-51 and Table 11-52 show the MISO flowgates which PJM and/or MISO took dispatch action to control during 2018 and 2017, and which had the greatest congestion cost impact on PJM. Total congestion costs associated with a given constraint may be positive or negative in value. The top congestion cost impacts for MISO flowgates affecting PJM and MISO dispatch are presented by constraint, in descending order of the absolute value of total congestion costs. Among MISO flowgates in 2018, the Tanners Creek – Miami Fort Flowgate made the most significant contribution to positive congestion while the Greentown Flowgate contributed to most negative congestion.

26 See "Joint Operating Agreement Between the Midwest Independent Transmission System Operator, Inc. and PJM Interconnection, L.L.C.," (December 11, 2008), Section 6.1, Effective Date: May 30, 2016. <http://www.pjm.com/documents/agreements.aspx>.

27 See "Joint Operating Agreement Between the Midwest Independent Transmission System Operator, Inc. and PJM Interconnection, L.L.C.," (December 11, 2008), Section 2.2.24, Effective Date: February 14, 2017. <http://www.pjm.com/documents/agreements.aspx>.

Table 11-51 Top 20 congestion cost impacts from MISO flowgates affecting PJM dispatch (By facility): 2018

		Congestion Costs (Millions)										
		Day-Ahead				Balancing					Event Hours	
No.	Constraint	Load Payments	Generation Credits	Explicit Costs	Total	Load Payments	Generation Credits	Explicit Costs	Total	Grand Total	Day-Ahead	Real-Time
1	Tanners Creek - Miami Fort	($20.8)	($94.1)	($2.9)	$70.4	$0.0	$0.0	$0.0	$0.0	$70.4	1,511	0
2	Batesville - Hubble	($13.1)	($55.9)	($10.3)	$32.5	($0.6)	($2.2)	$0.3	$2.0	$34.5	254	134
3	Northport - Albion	($2.3)	($18.4)	($3.8)	$12.3	($0.2)	($1.1)	$1.3	$2.2	$14.5	132	28
4	Brokaw - Leroy	$0.8	($12.3)	($4.4)	$8.6	$0.5	($1.3)	$3.0	$4.8	$13.5	1,232	261
5	Monroe - Lallendorf	($1.4)	($11.7)	($0.4)	$9.9	$0.0	$0.0	$0.0	$0.0	$9.9	945	0
6	Quad Cities - Cordova	($5.6)	($12.4)	$2.6	$9.4	$0.0	$0.0	$0.0	$0.0	$9.4	1,522	0
7	Flint Lake - Luchtman Road	$0.2	($10.6)	($4.9)	$5.8	($0.2)	($1.4)	$1.8	$3.0	$8.8	890	365
8	Olive	$0.2	($6.6)	$0.3	$7.0	$0.0	$0.0	$0.0	$0.0	$7.0	445	0
9	Pierce - Beckjord	($2.2)	($9.1)	($0.1)	$6.7	$0.0	$0.0	$0.0	$0.0	$6.7	263	0
10	Volunteer - Phipps Bend	($0.3)	($2.9)	($0.7)	$1.9	($1.0)	($3.2)	$1.1	$3.4	$5.3	7	38
11	Burnham - Munster	$0.6	($4.5)	$0.2	$5.2	$0.0	$0.0	$0.0	$0.0	$5.2	923	0
12	Segreto - Palisades	($0.2)	($6.0)	$0.6	$6.4	($0.1)	$0.1	($1.4)	($1.7)	$4.7	441	117
13	Plymouth - Leesburg	($1.9)	($7.7)	($2.0)	$3.7	($0.5)	$0.4	$1.5	$0.6	$4.4	306	163
14	Greentown	($0.0)	($0.8)	($0.2)	$0.6	($0.9)	$6.0	$2.0	($4.8)	($4.2)	151	72
15	Michigan City - Bosserman	($0.8)	($5.5)	($0.6)	$4.0	$0.0	$0.0	$0.0	$0.0	$4.0	809	0
16	Braidwood - East Frankfurt	($0.0)	($3.9)	($0.0)	$3.9	$0.0	$0.0	$0.0	$0.0	$3.9	74	0
17	Holland - Neoga	($0.6)	($4.3)	($0.1)	$3.5	$0.2	$0.0	$0.0	$0.2	$3.7	106	41
18	Northwest Tap - Purdue	($1.9)	($6.5)	($1.1)	$3.5	$1.1	$2.3	$1.3	$0.1	$3.6	477	242
19	Eugene - Cayuga	($0.4)	($4.4)	($0.6)	$3.4	$0.0	$0.0	($0.0)	($0.0)	$3.4	293	23
20	Roxana - Praxair	$2.8	($4.4)	($4.2)	$3.0	$3.2	$2.2	($7.2)	($6.2)	($3.2)	1,132	481
	Top 20 Total	($47.1)	($282.0)	($32.9)	$202.0	$1.6	$1.9	$3.8	$3.5	$205.6	11,913	1,965
	All Other Constraints	($9.0)	($57.0)	($3.5)	$44.4	$0.3	$5.4	($6.7)	($11.7)	$32.7	7,937	3,612
	Total	($56.1)	($338.9)	($36.4)	$246.5	$2.0	$7.3	($2.9)	($8.2)	$238.2	19,850	5,577

Table 11-52 Top 20 congestion cost impacts from MISO flowgates affecting PJM dispatch (By facility): 2017

		Congestion Costs (Millions)										
		Day-Ahead				Balancing					Event Hours	
No.	Constraint	Load Payments	Generation Credits	Explicit Costs	Total	Load Payments	Generation Credits	Explicit Costs	Total	Grand Total	Day-Ahead	Real-Time
1	Westwood	($22.1)	($41.3)	$0.5	$19.7	$1.2	$0.8	($0.5)	($0.1)	$19.6	3,399	198
2	Alpine - Belvidere	($2.3)	($14.0)	($0.9)	$10.8	$0.0	$0.0	$0.0	$0.0	$10.8	339	0
3	Lake George - Aetna	($1.1)	($9.0)	($1.5)	$6.4	($2.2)	$0.9	$5.9	$2.7	$9.1	483	244
4	Batesville - Hubble	($5.5)	($19.4)	($4.5)	$9.4	($0.1)	($1.3)	($1.7)	($0.5)	$8.9	379	158
5	Byron - Cherry Valley	($0.9)	($9.3)	($0.4)	$8.0	$0.0	$0.0	$0.0	$0.0	$8.0	347	0
6	Brokaw - Leroy	$0.8	($7.6)	($3.7)	$4.8	$0.2	$0.3	$2.6	$2.5	$7.3	1,744	528
7	Greentown	($1.4)	($7.6)	($0.7)	$5.6	($0.9)	($0.5)	$0.4	$0.0	$5.6	425	248
8	Havana E - Havana S	($2.6)	($8.3)	($0.2)	$5.5	$0.0	$0.0	$0.0	$0.0	$5.5	2,260	0
9	Dresden	($0.3)	($4.8)	($0.2)	$4.3	$0.0	$0.0	$0.0	$0.0	$4.3	1,216	0
10	Nelson	($2.2)	($6.6)	($0.3)	$4.1	$0.0	$0.0	$0.0	$0.0	$4.1	534	0
11	Shadelnd - Lafaysouth	($4.4)	($7.7)	$0.2	$3.5	$6.7	$4.7	($2.3)	($0.3)	$3.1	1,055	669
12	Nucor - Whitestown	($0.8)	($5.1)	($1.1)	$3.2	$0.1	$0.1	($0.1)	($0.1)	$3.1	519	19
13	Roxana - Praxair	($0.1)	$0.4	($0.5)	($1.0)	$1.4	$0.0	($3.4)	($2.0)	($3.0)	1,734	290
14	Todd Hunter	($0.6)	($3.6)	($0.0)	$2.9	$0.0	$0.0	$0.0	$0.0	$2.9	988	0
15	Burnham - Munster	$0.2	($2.3)	$0.2	$2.7	$0.0	$0.0	$0.0	$0.0	$2.7	760	0
16	Quad Cities	($1.3)	($3.8)	$0.2	$2.7	$0.0	$0.0	$0.0	$0.0	$2.7	460	0
17	Pleasant Prairie - Zion	($0.6)	($3.3)	($0.1)	$2.7	$0.0	$0.1	($0.2)	($0.2)	$2.4	2,052	395
18	Olive - Bosserman	$1.2	($1.5)	($0.4)	$2.3	$0.0	$0.0	$0.0	$0.0	$2.3	133	0
19	Havana South - Mason City West	($0.6)	($2.1)	$0.1	$1.6	$0.2	($0.3)	($0.0)	$0.4	$2.0	753	181
20	Reynolds - Magnetation	($0.3)	($1.9)	$0.4	$2.0	$0.0	($0.1)	($0.1)	($0.0)	$2.0	297	31
	Top 20 Total	($44.6)	($158.8)	($12.9)	$101.2	$6.6	$4.8	$0.6	$2.4	$103.6	19,877	2,961
	All Other Constraints	($6.2)	($46.0)	($11.7)	$28.1	$0.4	$0.8	($3.7)	($4.2)	$23.9	9,735	2,676
	Total	($50.9)	($204.8)	($24.6)	$129.3	$7.0	$5.7	($3.1)	($1.8)	$127.5	29,612	5,637

Congestion Event Summary for NYISO Flowgates

PJM and NYISO have a joint operating agreement (JOA) which defines a coordinated method for congestion management. This agreement establishes a structure and framework for the reliable operation of the interconnected PJM and NYISO transmission systems and efficient market operation through M2M coordination.[28] Only a subset of all transmission constraints that exist in either market are eligible for coordinated congestion management. This subset of transmission constraints is identified as M2M flowgates. Flowgates eligible for the M2M coordination process are called M2M flowgates.[29]

In 2018, none of the NYISO flowgates were binding and only one flowgate was binding in 2017. Table 11-53 shows the NYISO flowgates which PJM and/or NYISO took dispatch action to control during 2017.

Table 11-53 Congestion cost impact from NYISO flowgates affecting PJM dispatch (By facility): 2017

				Congestion Costs (Millions)										
				Day-Ahead				Balancing					Event Hours	
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit Costs	Total	Load Payments	Generation Credits	Explicit Costs	Total	Grand Total	Day-Ahead	Real-Time
1	Central East	Flowgate	NYISO	($2.7)	($5.7)	($1.7)	$1.3	$0.2	$0.4	($0.1)	($0.3)	$1.0	515	332
	Total			($2.7)	($5.7)	($1.7)	$1.3	$0.2	$0.4	($0.1)	($0.3)	$1.0	515	332

Congestion Event Summary for the 500 kV System

Constraints on the 500 kV system generally have a regional impact. Table 11-54 and Table 11-55 show the 500 kV constraints affecting congestion costs in PJM for 2018 and 2017. Total congestion costs are the sum of the day-ahead and balancing congestion cost components. Total congestion costs associated with a given constraint may be positive or negative in value. The 500 kV constraints affecting congestion costs in PJM are presented by constraint, in descending order of the absolute value of total congestion costs.

Table 11-54 Regional constraints summary (By facility): 2018

			Congestion Costs (Millions)										
			Day-Ahead				Balancing					Event Hours	
No.	Constraint	Type	Load Payments	Generation Credits	Explicit Costs	Total	Load Payments	Generation Credits	Explicit Costs	Total	Grand Total	Day-Ahead	Real-Time
1	AEP - DOM	Interface	$55.6	($66.9)	($5.3)	$117.2	$13.4	$18.7	$9.0	$3.8	$121.0	720	150
2	5004/5005 Interface	Interface	($15.4)	($54.4)	($4.4)	$34.6	$0.8	$1.7	$2.1	$1.1	$35.7	175	47
3	Conastone - Peach Bottom	Line	$29.8	$0.7	($0.2)	$28.9	$1.6	$0.8	($0.0)	$0.7	$29.6	1,100	422
4	Bedington - Black Oak	Interface	$10.2	($14.0)	($1.4)	$22.7	$0.6	$0.7	$0.6	$0.5	$23.2	316	52
5	AP South	Interface	$14.1	($8.3)	($1.6)	$20.8	$0.1	$0.1	($0.0)	($0.0)	$20.8	498	37
6	Yukon	Transformer	($2.6)	($9.7)	$0.3	$7.4	$0.6	$0.8	($0.5)	($0.7)	$6.8	102	58
7	CPL - DOM	Interface	$6.1	($1.2)	$0.8	$8.0	$0.3	$1.5	($0.4)	($1.6)	$6.4	272	98
8	West	Interface	($1.4)	($6.2)	($0.8)	$4.0	$0.0	($0.0)	($0.0)	($0.0)	$4.0	74	11
9	East	Interface	($2.3)	($5.9)	($0.1)	$3.5	($0.0)	$0.0	($0.1)	($0.1)	$3.4	107	2
10	502 Junction	Transformer	($0.3)	($2.9)	$0.0	$2.7	$0.0	$0.0	$0.0	$0.0	$2.7	37	0
11	Hunterstown	Transformer	($0.0)	($1.9)	$0.0	$1.9	$0.0	$0.0	$0.0	$0.0	$1.9	169	367
12	Central	Interface	($3.2)	($6.2)	($1.3)	$1.7	$0.0	$0.0	$0.0	$0.0	$1.7	28	0
13	Keeney - Rockspring	Line	($0.8)	($1.9)	$0.4	$1.5	$0.0	$0.0	$0.0	$0.0	$1.5	158	0
14	Breinigsville - Wescosville	Line	$0.0	($0.2)	$0.4	$0.6	$0.0	$0.0	$0.0	$0.0	$0.6	108	0
15	Limerick	Transformer	($0.1)	($0.5)	$0.1	$0.4	$0.0	$0.0	$0.0	$0.0	$0.4	103	0
16	Hopatcong - Lackawanna	Line	$0.0	$0.0	$0.0	$0.0	$0.0	($0.1)	$0.0	$0.1	$0.1	0	46
17	Wylie Ridge	Transformer	$0.0	$0.0	$0.0	$0.0	$0.0	($0.0)	($0.2)	($0.1)	($0.1)	0	4
18	Three Mile Island	Transformer	$0.0	($0.1)	($0.0)	$0.1	$0.0	$0.0	$0.0	$0.0	$0.1	4	0
19	Valley - Bath County	Line	($0.0)	($0.1)	$0.0	$0.1	$0.0	$0.0	$0.0	$0.0	$0.1	2	0
20	Conastone	Transformer	$0.0	($0.0)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	4	0
	Top 20 Total		$89.4	($179.7)	($12.9)	$256.2	$17.5	$24.2	$10.4	$3.6	$259.8	3,977	1,294
	All Other Constraints		($0.0)	($0.1)	$0.0	$0.1	$0.0	$0.0	($0.0)	$0.0	$0.1	18	5
	Total		$89.4	($179.8)	($12.9)	$256.3	$17.5	$24.2	$10.4	$3.6	$259.9	3,995	1,299

28 See "New York Independent System Operator, Inc. NYISO Tariffs," (June 21, 2017) Section 35.3.1, Effective Date: January 15, 2013. <http://www.pjm.com/documents/agreements.aspx>.
29 See "New York Independent System Operator, Inc. NYISO Tariffs," (June 21, 2017) Section 35.23, Effective Date: May 1, 2017. <http://www.pjm.com/documents/agreements.aspx>.

Table 11-55 Regional constraints summary (By facility): 2017

			Congestion Costs (Millions)										
			Day-Ahead				Balancing					Event Hours	
No.	Constraint	Type	Load Payments	Generation Credits	Explicit Costs	Total	Load Payments	Generation Credits	Explicit Costs	Total	Grand Total	Day-Ahead	Real-Time
1	Conastone - Peach Bottom	Line	$38.7	$1.6	$0.1	$37.2	$1.7	$1.2	$1.6	$2.0	$39.3	3,159	840
2	5004/5005 Interface	Interface	($9.9)	($38.7)	($3.8)	$25.0	$4.5	$11.4	$4.6	($2.4)	$22.7	173	105
3	AP South	Interface	$15.3	($9.2)	($2.4)	$22.1	($0.0)	$1.3	$0.9	($0.5)	$21.6	1,315	75
4	Three Mile Island	Transformer	$7.4	($4.9)	($0.3)	$11.9	($0.1)	($0.5)	$0.9	$1.3	$13.3	540	86
5	Bedington - Black Oak	Interface	$5.5	($4.1)	($0.2)	$9.3	$0.1	$0.3	$0.4	$0.2	$9.5	1,215	62
6	AEP - DOM	Interface	$3.3	($4.3)	($0.1)	$7.5	$0.5	$0.4	$0.2	$0.3	$7.8	948	32
7	West	Interface	($0.4)	($2.1)	($0.2)	$1.6	$0.0	$0.0	$0.0	$0.0	$1.6	180	0
8	Limerick	Transformer	($0.0)	($1.4)	($0.0)	$1.3	$0.0	$0.0	$0.0	$0.0	$1.3	142	5
9	Conastone	Transformer	$0.3	($0.1)	$0.0	$0.4	$0.0	$0.0	$0.0	$0.0	$0.4	33	2
10	Cabot - Keystone	Line	($0.1)	($0.5)	$0.1	$0.5	$0.1	$0.2	($0.0)	($0.2)	$0.3	97	18
11	East	Interface	($0.5)	($1.1)	($0.1)	$0.6	$0.2	$0.7	$0.2	($0.3)	$0.3	131	10
12	Belmont	Transformer	($0.0)	($0.2)	($0.1)	$0.1	$0.0	$0.1	($0.3)	($0.4)	($0.3)	42	52
13	Keeney - Rockspring	Line	($0.1)	($0.3)	$0.0	$0.2	$0.0	$0.0	$0.0	$0.0	$0.2	39	0
14	502 Junction	Transformer	$0.0	($0.1)	$0.0	$0.1	$0.0	$0.0	$0.0	$0.0	$0.1	42	0
15	Bristers - Ox	Line	$0.0	($0.0)	$0.0	$0.1	$0.0	$0.0	$0.0	$0.0	$0.1	14	0
16	Redlion	Transformer	$0.0	($0.1)	$0.0	$0.1	$0.0	$0.0	$0.0	$0.0	$0.1	55	0
17	Central	Interface	($0.1)	($0.2)	($0.0)	$0.1	$0.0	$0.0	$0.0	$0.0	$0.1	2	0
18	Elroy - Hosensack	Line	($0.0)	($0.1)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	7	0
19	Cabot	Other	($0.0)	($0.1)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	8	0
20	Hope Creek - Red Lion	Line	$0.0	($0.0)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	15	0
	Top 20 Total		$59.3	($65.8)	($6.8)	$118.3	$6.9	$15.2	$8.5	$0.2	$118.4	8,157	1,287
	All Other Constraints		$0.0	($0.0)	$0.0	$0.1	$0.0	$0.0	($0.0)	($0.0)	$0.1	62	1
	Total		$59.3	($65.8)	($6.8)	$118.3	$6.9	$15.2	$8.5	$0.2	$118.5	8,219	1,288

Congestion Costs by Physical and Financial Participants

In order to evaluate the recipients and payers of congestion, the MMU categorized all participants in PJM as either physical or financial. Physical entities include utilities and customers which primarily take physical positions in PJM markets. Financial entities include banks and hedge funds which primarily take financial positions in PJM markets. International market participants that primarily take financial positions in PJM markets are generally considered to be financial entities even if they are utilities in their own countries.

Financial entities received $9.1 million in net congestion credits in 2018 and received $18.2 million in net congestion credits in 2017 (Table 11-56 and Table 11-57). Physical entities paid $1,319.0 million in congestion charges in 2018 and $715.8 million in congestion charges in 2017.

Table 11-56 Congestion cost by type of participant: 2018

	Congestion Costs (Millions)									
	Day-Ahead				Balancing					
	Load Payments	Generation Credits	Explicit Costs	Total	Load Payments	Generation Credits	Explicit Costs	Total	Inadvertent Charges	Grand Total
Financial	$48.9	($2.6)	($36.9)	$14.6	($31.9)	$5.7	$13.9	($23.8)	($0.0)	($9.1)
Physical	$300.3	($1,045.9)	$18.0	$1,364.3	$43.4	$56.3	($32.4)	($45.3)	$0.0	$1,319.0
Total	$349.3	($1,048.6)	($18.9)	$1,378.9	$11.5	$62.0	($18.5)	($69.0)	$0.0	$1,309.9

Table 11-57 Congestion cost by type of participant: 2017

	Congestion Costs (Millions)									
	Day-Ahead				Balancing					
	Load Payments	Generation Credits	Explicit Costs	Total	Load Payments	Generation Credits	Explicit Costs	Total	Inadvertent Charges	Grand Total
Financial	$19.5	$14.6	($18.3)	($13.4)	($11.7)	($7.9)	($0.9)	($4.8)	$0.0	($18.2)
Physical	$168.0	($568.7)	$9.8	$746.5	$33.9	$55.0	($9.5)	($30.7)	$0.0	$715.8
Total	$187.6	($554.1)	($8.6)	$733.1	$22.2	$47.2	($10.4)	($35.5)	$0.0	$697.6

Congestion Event Summary: Impact of Changes in UTC Volumes

UTCs have a significant impact on congestion events in the day-ahead market and, as a result, contribute to differences between day-ahead and real-time congestion events. The greater the volume of UTCs, the greater the number of congestion events in the day-ahead market and the greater the differences between the day-ahead and real-time congestion events.

In 2016, the average hourly UTC submitted MW increased 70.3 percent and UTC cleared MW increased 78.6 percent, compared to 2015.[30] Figure 11-5 shows that day-ahead congestion event hours decreased significantly after September 8, 2014, when UTC activity declined as a result of a FERC order, and increased after December 7, 2015 when UTC activity increased, as a result of a FERC order. Figure 11-5 also shows that day-ahead congestion event hours decreased again on February 22, 2018, when UTC activity declined, as a result of a FERC order.

In 2018, the average hourly UTC submitted MW decreased by 57.3 percent and UTC cleared MW decreased 48.7 percent, compared to 2017. Day-ahead congestion event hours decreased by 55.9 percent from 300,923 congestion event hours in 2017 to 132,598 congestion event hours in 2018 (Table 11-22). Day-ahead congestion event hours decreased by 64.8 percent from 250,535 congestion event hours for the period February 22, 2017, through December 31, 2017, to 88,078 congestion event hours for the period February 22, 2018 through December 31, 2018.

Figure 11-5 shows the daily day-ahead and real-time congestion event hours for January 1, 2014 through December 31, 2018.

Figure 11-5 Daily congestion event hours: 2014 through 2018

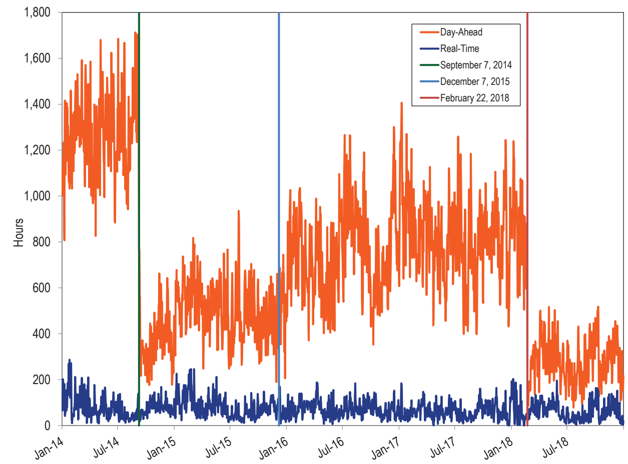


Figure 11-6 shows the change in up to congestion balancing explicit congestion costs from January 1, 2014, through December 31, 2018. Within this period, Figure 11-6 shows the highest monthly payment ($55.1 million) in balancing congestion credits to up to congestion transactions occurred in March 2015 and the highest monthly charge ($29.5 million) in balancing congestion charges occurred in January 2018. Figure 11-6 shows that UTCs are a significant net contributor to balancing congestion in PJM. As shown in Figure 11-6, UTCs are generally paid balancing congestion, which takes the form of negative balancing congestion charges being allocated to UTC positions.

Figure 11-6 Monthly balancing congestion cost incurred by up to congestion: 2014 through 2018

30 See *2016 State of the Market Report for PJM*, Vol. 2 Section 3: Energy Market, Table 3-35.

Balancing congestion is caused by settling real time deviations from day-ahead positions at real-time prices. Whether balancing congestion is positive or negative depends on the differences that exist between the day-ahead and real-time market models including modeled constraints, transfer capability (line limits) of the modeled constraints, the location of deviations and deviations in flows caused by these modeling differences and the differences in day-ahead and real-time LMPs that result from the interaction among these elements. For example, one source of negative balancing congestion is that the PJM system has less transmission transfer capability in the real time market than in the day-ahead market. Due to the complexity of the day-ahead unit commitment process, PJM only enforces or models a subset of its physical transmission limits in the day-ahead market. Transmission constraints not modeled in the day-ahead market have effectively unlimited transfer capability in the day-ahead market model. The reduction in transmission capability between the day-ahead and real-time market between high and low cost generation sources, holding load constant, requires the use of more high cost generation and the use of less low cost generation to serve load, which means a decrease in congestion. This results in a net increase in generation credits relative to what was incurred in the day-ahead and, holding load constant, no change in load charges. The increase in generation credits relative to load charges causes negative balancing congestion. Negative balancing congestion reduces total congestion collected from the day-ahead position, as the net difference between load charges and generation credits is reduced relative to the day-ahead results.

Due to the nature of the modeling differences between the day-ahead and real-time market, PJM has more system flow capability in the day-ahead market than it does in the real-time market. As a day-ahead spread bid, UTCs are uniquely suited to take advantage of and profit from LMP differences caused by market and transmission modeling differences between the day-ahead and real-time market. UTCs generate flows in the day ahead market that are not physically possible in the real-time market, clearing between source and sink points with little or no price differences in the day-ahead market, and settling the resulting deviations at higher real-time prices in the real-time market. The general result is negative balancing congestion is caused by and paid to UTCs.

Table 11-58 provides an example of how UTCs can interact with, and profit from, differences in day-ahead and real-time transmission limits and generate negative balancing congestion. In the example, Bus A and Bus B are linked by a transmission line. In the day-ahead market the transmission limit is modeled as 9,999 MW (no limit is enforced in the day-ahead market solution). In the real-time market the physical limit between bus A and bus B is 50 MW. Generation at A has a price of $1.00 and Generation at B has a price of $6. There is 100 MW of load at bus A and 100 MW of load at bus B. There is a UTC of 200 MW that will source at bus A and sink at bus B if the spread in the prices between A and B is less than $1.

As a result of the fact that the transmission capability between A and B is unlimited in the day-ahead market, all of load at A and B can be met with the $1 generation at bus A. The constraint between A and B does not bind in day-ahead so the price at A and B is $1. The price spread between bus A and bus B is zero, which is less than the UTC spread requirement of $1, so the UTC clears. The UTC causes a 200 MW injection at A and 200 MW withdrawal at B, creating 200 MW of flow between bus A and bus B. The 300 MW of combined flow from generation at A and UTC injections at A to the load and UTC sink at B does not exceed the DA modeled limit between A and B. This means that all 200 MW of the UTC injection at A and 200 MW of withdrawal at B can clear without forcing a price spread between A and D. Total day-ahead congestion, which is the difference between congestion charges and credits, is zero. There is no price difference between the two nodes and every MW of injection and every MW of withdrawal at bus A and bus B settles at the same price.

In the real-time market, the transmission line between bus A and bus B has a 50 MW limit. The UTC does not physically exist in the real-time market and therefore generates deviations at Bus A (-200 MW) and at Bus B (+200 MW). The load at A (100 MW) and B (100 MW) does not change, so there are no load deviations. With only 50 MW of transmission capability between A and B, the generation at A cannot be used to meet total load on the system. Generation from A meets the load at A (100 MW) and can supply only 50 MW of the 100 MW of load at B. Due to the binding constraint between A and B, the remaining 50 MW of load at B must be met with local generation at B at a cost of $6 and the price at A remains $1.

The reduction in transmission capability between A and B requires a 50 MW reduction in relatively inexpensive $1 generation at A and the use of 50 MW of relatively expensive $6 generation at B. The UTC must settle its deviation MW (-200 MW at A and +200MW at B) at the real-time price of $1 at A and $6 at B. The UTC pays $200 to settle its position at A and is paid $1,200 to settle its position at B. The resulting net payment to the UTC is $1,000 in balancing credits.

Table 11-58 shows the balancing credits and charges generated by the real-time deviations by source in the example. Total congestion (day-ahead plus balancing congestion) in this example is negative $1,250, with net total congestion credits (payments) to generation and the UTC exceeding the total charges collected from load. The negative balance owed to generation and the UTC is billed to the load as negative balancing congestion, under the recent FERC order.

Due to the modeling differences, the UTC did not contribute to price convergence between the day-ahead and real-time market and did not improve efficiency in system dispatch or commitment. The UTC did significantly increase the cost of energy to the load, with load paying the UTC $1,000 in negative balancing, over and above the costs of generation that was needed to meet realized load at bus A and bus B.

Table 11-58 Example of UTC causing and profiting from negative balancing congestion

Prices	Bus A	Transfer Capability (Line Limit MW)	Bus B	
LMP DA	$1.00	9,999	$1.00	
LMP RT	$1.00	50	$6.00	
Day-Ahead MW	**Bus A**		**Bus B**	**Total MW**
Day-Ahead Generation	200		0	200
Day-Ahead Load	(100)		(100)	(200)
Day-Ahead UTC (+/-)	200		(200)	0
Total MW	300		(300)	0
Day-Ahead Credits and Charges	**Bus A**		**Bus B**	**Total Day-Ahead Congestion**
Total DA Gen Credits	$200.00		$0.00	
Total DA Load Charges	$100.00		$100.00	
Total DA UTC Credits	$200.00		($200.00)	
Total DA Credits	$300.00		($300.00)	$0.00
Total Day-Ahead Congestion (Charges - Credits)				$0.00
Balancing Deviation MW	**Bus A**		**Bus B**	**Total Deviations**
RT GEN Deviations	(50)		50	
RT Load Deviations	0		0	
DA UTC (+/-)	(200)		200	
Total Deviations	(250)		250	0
Balancing Credits and Charges	**Bus A**		**Bus B**	**Balancing Congestion Credits**
Total BA Gen Credits	($50.00)		$300.00	$250.00
Total BA Load Charges	$0.00		$0.00	
Total BA UTC Credits	($200.00)		$1,200.00	$1,000.00
Total BA Credits	($250.00)		$1,500.00	$1,250.00
Total Balancing Congestion (Charges - Credits)				($1,250.00)

Marginal Losses

Marginal Loss Accounting

Marginal losses occur in the Day-Ahead and Real-Time Energy Markets. PJM calculates marginal loss costs for each PJM member. The loss cost is based on the applicable day-ahead and real-time marginal loss component of LMP (MLMP). Each PJM member is charged for the cost of losses on the transmission system. Total marginal loss costs, analogous to total congestion costs, are equal to the net of the load loss payments minus generation loss credits, plus explicit loss costs, incurred in both the Day-Ahead Energy Market and the balancing energy market.

Total marginal loss costs can be more accurately thought of as net marginal loss costs. Total marginal loss costs equal net implicit marginal loss costs plus net explicit marginal loss costs plus net inadvertent loss charges. Net implicit marginal loss costs equal load loss payments minus generation loss credits. Net explicit marginal loss costs are the net marginal loss costs associated with point to point energy transactions. Net inadvertent loss charges are the losses associated with the hourly difference between the net actual energy flow and the net scheduled energy flow into or out of the PJM control area.[31] Unlike the other categories of marginal loss accounting, inadvertent loss charges are common costs not directly attributable to specific participants. Inadvertent loss charges are assigned to participants based on real-time load (excluding losses) ratio share.[32] Each of these categories of marginal loss costs is comprised of day-ahead and balancing marginal loss costs.

Marginal loss costs can be both positive and negative and consequently load payments and generation credits can also be both positive and negative. Total loss costs, when positive, measure the total loss payment by a PJM member and when negative, measure the total loss credit paid to a PJM member. Load loss payments, when positive, measure the total loss payment by a PJM member and when negative, measure the total loss credit paid to a PJM member. Generation loss credits, when negative, measure the total loss payment by a PJM member and when positive, measure the total loss credit paid to a PJM member.

The loss component of LMP is calculated with respect to the system marginal price (SMP). An increase in generation at a bus that results in an increase in losses will cause the marginal loss component of that bus to be negative. If the increase in generation at the bus results in a decrease of system losses, then the marginal loss component is positive.

Day-ahead marginal loss costs are based on day-ahead MWh priced at the marginal loss price component of LMP. Balancing marginal loss costs are based on the load or generation deviations between the Day-Ahead and Real-Time Energy Markets priced at the marginal loss price component of LMP in the Real-Time Energy Market. If a participant has real-time generation or load that is greater than its day-ahead generation or load then the deviation will be positive. If there is a positive load deviation at a bus where the real-time LMP has a positive marginal loss component, positive balancing marginal loss costs will result. Similarly, if there is a positive load deviation at a bus where real-time LMP has a negative marginal loss component, negative balancing marginal loss costs will result. If a participant has real-time generation or load that is less than its day-ahead generation or load then the deviation will be negative. If there is a negative load deviation at a bus where real-time LMP has a positive marginal loss component, negative balancing marginal loss costs will result. Similarly, if there is a negative load deviation at a bus where real-time LMP has a negative marginal loss component, positive balancing marginal loss costs will result.

The total loss surplus is the remaining loss amount from collection of marginal losses, after accounting for total energy costs and net residual market adjustments that is allocated to PJM market participants based on real-time load plus export ratio share as marginal loss credits.[33]

- **Day-Ahead Load Loss Payments.** Day-ahead load loss payments are calculated for all cleared demand, decrement bids and day-ahead energy market sale transactions. Day-ahead, load loss payments are calculated using MW and the load bus MLMP, the decrement bid MLMP or the MLMP at the source of the sale transaction.

31 PJM Operating Agreement Schedule 1 §3.7.
32 *Id.*
33 See PJM. "Manual 28: Operating Agreement Accounting," Rev. 81 (Oct. 25. 2018)

- **Day-Ahead Generation Loss Credits.** Day-ahead generation loss credits are calculated for all cleared generation and increment offers and day-ahead energy market purchase transactions. Day-ahead, generation loss credits are calculated using MW and the generator bus MLMP, the increment offer MLMP or the MLMP at the sink of the purchase transaction.
- **Balancing Load Loss Payments.** Balancing load loss payments are calculated for all deviations between a PJM member's real-time load and energy sale transactions and their day-ahead cleared demand, decrement bids and energy sale transactions. Balancing, load loss payments are calculated using MW deviations and the real-time MLMP for each bus where a deviation exists.
- **Balancing Generation Loss Credits.** Balancing generation loss credits are calculated for all deviations between a PJM member's real-time generation and energy purchase transactions and the day-ahead cleared generation, increment offers and energy purchase transactions. Balancing, generation loss credits are calculated using MW deviations and the real-time MLMP for each bus where a deviation exists.
- **Explicit Loss Costs.** Explicit loss costs are the net loss costs associated with point to point energy transactions, including UTCs. These costs equal the product of the transacted MW and MLMP differences between sources (origins) and sinks (destinations) in the Day-Ahead Energy Market. Balancing energy market explicit loss costs equal the product of the differences between the real-time and day-ahead transacted MW and the differences between the real-time MLMP at the transactions' sources and sinks.
- **Inadvertent Loss Charges.** Inadvertent loss charges are the net loss charges resulting from the differences between the net actual energy flow and the net scheduled energy flow into or out of the PJM control area each hour. This inadvertent interchange of energy may be positive or negative, where positive interchange typically results in a charge while negative interchange typically results in a credit. Inadvertent loss charges are common costs, not directly attributable to specific participants, that are distributed on a load ratio basis.[34]

Total Marginal Loss Cost

The total marginal loss cost in PJM for 2018 was $960.1 million, which was comprised of load loss payments of -$70.6 million, generation loss credits of -$1,042.7 million, explicit loss costs of -$11.9 million and inadvertent loss charges of $0.0 million (Table 11-60).

Monthly marginal loss costs in 2018 ranged from $49.5 million in February to $222.8 million in January. Total marginal loss surplus increased in 2018 by $105.6 million or 49.2 percent from $214.6 million in 2017 to $320.2 million in 2018.

Table 11-59 shows the total marginal loss component costs and the total PJM billing for 2008 through 2018.

Table 11-59 Total PJM loss component costs (Dollars (Millions)): 2008 through 2018[35]

	Loss Costs	Percent Change	Total PJM Billing	Percent of PJM Billing
2008	$2,497	NA	$34,306	7.3%
2009	$1,268	(49.2%)	$26,550	4.8%
2010	$1,635	29.0%	$34,771	4.7%
2011	$1,380	(15.6%)	$35,887	3.8%
2012	$982	(28.8%)	$29,181	3.4%
2013	$1,035	5.5%	$33,860	3.1%
2014	$1,466	41.6%	$50,030	2.9%
2015	$969	(33.9%)	$42,630	2.3%
2016	$697	(28.1%)	$39,050	1.8%
2017	$691	(0.8%)	$40,170	1.7%
2018	$960	39.0%	$49,790	1.9%

Table 11-60 shows PJM total marginal loss costs by accounting category for 2008 through 2018. Table 11-61 shows PJM total marginal loss costs by accounting category by market for 2008 through 2018.

34 PJM Operating Agreement Schedule 1 §3.7.
35 The loss costs include net inadvertent charges.

Table 11-60 Total PJM marginal loss costs by accounting category (Dollars (Millions)): 2008 through 2018

	Marginal Loss Costs (Millions)				
	Load Payments	Generation Credits	Explicit Costs	Inadvertent Charges	Total
2008	($237.2)	($2,641.5)	$92.4	$0.0	$2,496.7
2009	($78.5)	($1,314.3)	$32.0	($0.0)	$1,267.7
2010	($122.3)	($1,707.0)	$50.2	($0.0)	$1,634.8
2011	($174.0)	($1,551.9)	$1.6	$0.0	$1,379.5
2012	($11.1)	($1,036.8)	($44.0)	$0.0	$981.7
2013	($4.1)	($1,083.3)	($43.9)	($0.0)	$1,035.3
2014	($59.2)	($1,581.3)	($56.0)	$0.0	$1,466.1
2015	($31.7)	($1,021.0)	($20.5)	$0.0	$968.7
2016	($55.0)	($782.1)	($30.6)	($0.0)	$696.5
2017	($40.9)	($766.9)	($35.1)	$0.0	$690.8
2018	($70.6)	($1,042.7)	($11.9)	$0.0	$960.1

Table 11-61 Total PJM marginal loss costs by accounting category by market (Dollars (Millions)): 2008 through 2018

	Marginal Loss Costs (Millions)									
	Day-Ahead				Balancing					
	Load Payments	Generation Credits	Explicit Costs	Total	Load Payments	Generation Credits	Explicit Costs	Total	Inadvertent Charges	Grand Total
2008	($158.1)	($2,582.2)	$134.3	$2,558.4	($79.1)	($59.4)	($42.0)	($61.7)	$0.0	$2,496.7
2009	($84.7)	($1,311.7)	$65.4	$1,292.3	$6.2	($2.7)	($33.5)	($24.6)	($0.0)	$1,267.7
2010	($146.3)	($1,716.1)	$95.8	$1,665.6	$23.9	$9.1	($45.6)	($30.8)	($0.0)	$1,634.8
2011	($215.4)	($1,592.1)	$53.8	$1,430.5	$41.4	$40.2	($52.2)	($51.0)	$0.0	$1,379.5
2012	($43.0)	($1,060.3)	($13.4)	$1,003.8	$32.0	$23.4	($30.6)	($22.1)	$0.0	$981.7
2013	($37.1)	($1,112.4)	$62.4	$1,137.8	$33.0	$29.1	($106.4)	($102.5)	($0.0)	$1,035.3
2014	($113.9)	($1,618.8)	$66.6	$1,571.4	$54.7	$37.5	($122.5)	($105.3)	$0.0	$1,466.1
2015	($53.4)	($1,032.2)	$33.8	$1,012.6	$21.7	$11.3	($54.3)	($43.9)	$0.0	$968.7
2016	($61.7)	($781.6)	$53.4	$773.2	$6.8	($0.5)	($84.0)	($76.7)	($0.0)	$696.5
2017	($52.2)	($767.2)	$54.9	$769.9	$11.3	$0.3	($90.0)	($79.1)	$0.0	$690.8
2018	($76.7)	($1,032.2)	$41.7	$997.2	$6.1	($10.5)	($53.7)	($37.1)	$0.0	$960.1

Table 11-62 and Table 11-63 show the total loss costs for each transaction type in 2018 and 2017. In 2018, generation paid loss costs of $976.7 million, 101.7 percent of total loss costs. In 2017, generation paid loss costs of $731.9 million, 105.9 percent of total loss costs.

Virtual transaction loss costs, when positive, measure the total loss costs to virtual transactions and when negative, measure the total loss credits to virtual transaction. In 2018, DECs were paid $2.0 million in loss credits in the day-ahead market, paid $2.7 million in loss costs in the balancing energy market and paid $0.7 million in total loss payments. In 2018, INCs paid $13.6 million in loss costs in the day-ahead market, were paid $15.0 million in loss credits in the balancing energy market and were paid $1.4 million in total loss credits. In 2018, up to congestion paid $42.3 million in loss costs in the day-ahead market, were paid $53.3 million in loss credits in the balancing energy market and received $11.0 million in total loss credits.

Table 11-62 Total PJM loss costs by transaction type by market (Dollars (Millions)): 2018

	Marginal Loss Costs (Millions)									
	Day-Ahead				Balancing					
Transaction Type	Load Payments	Generation Credits	Explicit Costs	Total	Load Payments	Generation Credits	Explicit Costs	Total	Inadvertent Charges	Grand Total
DEC	($2.0)	$0.0	$0.0	($2.0)	$2.7	$0.0	$0.0	$2.7	$0.0	$0.7
Demand	($7.6)	$0.0	$0.0	($7.6)	$12.2	$0.0	$0.0	$12.2	$0.0	$4.5
Demand Response	($0.0)	$0.0	$0.0	($0.0)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Explicit Congestion and Loss Only	$0.0	$0.0	($0.7)	($0.7)	$0.0	$0.0	($0.1)	($0.1)	$0.0	($0.7)
Export	($24.6)	$0.0	$0.0	($24.6)	($9.3)	$0.0	$0.4	($8.9)	$0.0	($33.5)
Generation	$0.0	($973.2)	$0.0	$973.2	$0.0	($3.5)	$0.0	$3.5	$0.0	$976.7
Grandfathered Overuse	$0.0	$0.0	($0.4)	($0.4)	$0.0	$0.0	($0.1)	($0.1)	$0.0	($0.5)
Import	$0.0	($3.4)	$0.0	$3.4	$0.0	($22.5)	($0.5)	$22.1	$0.0	$25.5
INC	$0.0	($13.6)	$0.0	$13.6	$0.0	$15.0	$0.0	($15.0)	$0.0	($1.4)
Internal Bilateral	($14.0)	($13.6)	$0.5	$0.0	$0.5	$0.5	$0.0	($0.0)	$0.0	($0.0)
Up to Congestion	$0.0	$0.0	$42.3	$42.3	$0.0	$0.0	($53.3)	($53.3)	$0.0	($11.0)
Wheel In	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	($0.1)	($0.1)	$0.0	($0.1)
Total	($48.3)	($1,003.8)	$41.7	$997.2	$6.1	($10.5)	($53.7)	($37.1)	$0.0	$960.1

Table 11-63 Total PJM loss costs by transaction type by market (Dollars (Millions)): 2017

	Marginal Loss Costs (Millions)									
	Day-Ahead				Balancing					
Transaction Type	Load Payments	Generation Credits	Explicit Costs	Total	Load Payments	Generation Credits	Explicit Costs	Total	Inadvertent Charges	Grand Total
DEC	($7.7)	$0.0	$0.0	($7.7)	$6.0	$0.0	$0.0	$6.0	$0.0	($1.7)
Demand	($5.6)	$0.0	$0.0	($5.6)	$11.4	$0.0	$0.0	$11.4	$0.0	$5.8
Demand Response	($0.0)	$0.0	$0.0	($0.0)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Export	($17.3)	$0.0	$0.1	($17.2)	($7.8)	$0.0	$0.8	($7.0)	$0.0	($24.3)
Generation	$0.0	($730.0)	$0.0	$730.0	$0.0	($1.9)	$0.0	$1.9	$0.0	$731.9
Grandfathered Overuse	$0.0	$0.0	($0.5)	($0.5)	$0.0	$0.0	($0.4)	($0.4)	$0.0	($0.9)
Import	$0.0	($1.9)	$0.0	$1.9	$0.0	($11.5)	($0.3)	$11.2	$0.0	$13.1
INC	$0.0	($13.8)	$0.0	$13.8	$0.0	$12.0	$0.0	($12.0)	$0.0	$1.8
Internal Bilateral	($21.6)	($21.5)	$0.1	$0.0	$1.7	$1.7	$0.0	($0.0)	$0.0	($0.0)
Up to Congestion	$0.0	$0.0	$54.9	$54.9	$0.0	$0.0	($90.0)	($90.0)	$0.0	($35.1)
Wheel In	$0.0	$0.0	$0.4	$0.4	$0.0	$0.0	($0.0)	($0.0)	$0.0	$0.3
Total	($52.2)	($767.2)	$54.9	$769.9	$11.3	$0.3	($90.0)	($79.1)	$0.0	$690.9

Monthly Marginal Loss Costs

Table 11-64 shows a monthly summary of marginal loss costs by market type for 2017 and 2018.

Table 11-64 Monthly marginal loss costs by market (Millions): 2017 and 2018

	Marginal Loss Costs (Millions)							
	2017				2018			
	Day-Ahead Total	Balancing Total	Inadvertent Charges	Grand Total	Day-Ahead Total	Balancing Total	Inadvertent Charges	Grand Total
Jan	$75.5	($13.2)	($0.0)	$62.3	$227.1	($4.3)	$0.0	$222.8
Feb	$54.2	($7.8)	$0.0	$46.4	$52.7	($3.2)	$0.0	$49.5
Mar	$70.2	($7.4)	$0.0	$62.8	$67.2	$0.0	$0.0	$67.2
Apr	$50.8	($6.6)	$0.0	$44.2	$56.3	($0.9)	$0.0	$55.4
May	$55.0	($4.9)	$0.0	$50.1	$64.5	($1.1)	$0.0	$63.4
Jun	$59.0	($4.2)	$0.0	$54.8	$66.5	($3.4)	($0.0)	$63.2
Jul	$78.7	($7.1)	$0.0	$71.6	$85.7	($3.5)	$0.0	$82.2
Aug	$64.4	($7.6)	$0.0	$56.8	$87.7	($4.6)	$0.0	$83.1
Sep	$58.3	($6.2)	$0.0	$52.0	$73.2	($2.9)	$0.0	$70.2
Oct	$51.8	($4.7)	$0.0	$47.1	$65.0	($3.0)	($0.0)	$62.1
Nov	$55.3	($4.0)	$0.0	$51.3	$77.6	($5.4)	($0.0)	$72.2
Dec	$96.8	($5.3)	$0.0	$91.5	$73.7	($4.8)	($0.0)	$68.9
Total	$769.9	($79.1)	$0.0	$690.8	$997.2	($37.1)	$0.0	$960.1

Figure 11-7 shows PJM monthly marginal loss costs for 2008 through 2018.

Figure 11-7 PJM monthly marginal loss costs (Dollars (Millions)): 2008 through 2018

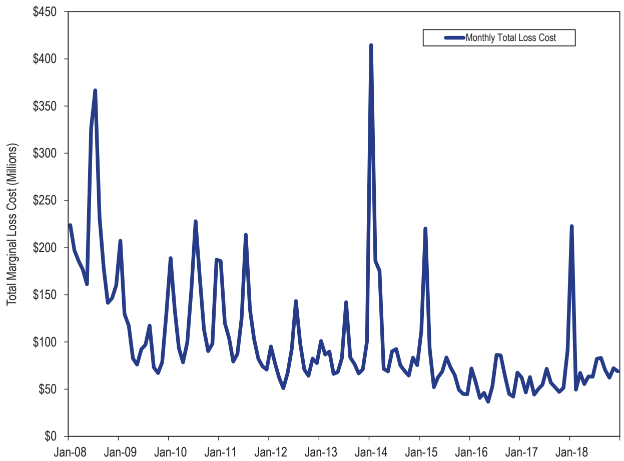


Table 11-65 and Table 11-66 show the monthly total loss costs for each virtual transaction type in 2018 and 2017.

Table 11-65 Monthly PJM loss costs by virtual transaction type and by market (Dollars (Millions)): 2018

	Marginal Loss Costs (Millions)									
	DEC			INC			Up to Congestion			
	Day-Ahead	Balancing	Total	Day-Ahead	Balancing	Total	Day-Ahead	Balancing	Total	Grand Total
Jan	$0.2	($0.5)	($0.3)	$2.1	($2.4)	($0.2)	$6.6	($8.5)	($1.9)	($2.5)
Feb	($0.2)	$0.0	($0.1)	$0.5	($0.5)	($0.1)	$2.5	($3.9)	($1.4)	($1.6)
Mar	($0.0)	$0.2	$0.2	$1.3	($1.4)	($0.1)	$1.2	($1.5)	($0.3)	($0.2)
Apr	($0.1)	$0.2	$0.1	$1.1	($1.2)	($0.2)	$1.5	($2.1)	($0.6)	($0.7)
May	($0.5)	$0.5	$0.0	$1.1	($1.2)	($0.1)	$2.2	($2.8)	($0.6)	($0.7)
Jun	($0.3)	$0.5	$0.2	$1.1	($1.1)	($0.0)	$3.0	($3.5)	($0.4)	($0.3)
Jul	($0.1)	$0.2	$0.1	$0.8	($0.8)	($0.0)	$3.8	($4.4)	($0.7)	($0.6)
Aug	($0.2)	$0.1	($0.1)	$1.0	($1.1)	($0.1)	$4.4	($5.8)	($1.3)	($1.5)
Sep	($0.3)	$0.5	$0.3	$1.2	($1.4)	($0.1)	$3.8	($4.6)	($0.7)	($0.6)
Oct	($0.3)	$0.4	$0.1	$1.2	($1.3)	($0.1)	$3.3	($4.0)	($0.7)	($0.6)
Nov	($0.0)	$0.2	$0.1	$1.5	($1.6)	($0.1)	$5.4	($6.5)	($1.1)	($1.1)
Dec	($0.2)	$0.4	$0.1	$0.7	($0.9)	($0.2)	$4.6	($5.8)	($1.3)	($1.3)
Total	($2.0)	$2.7	$0.7	$13.6	($15.0)	($1.4)	$42.3	($53.3)	($11.0)	($11.8)

Table 11-66 Monthly PJM loss costs by virtual transaction type and by market (Dollars (Millions)): 2017

	Marginal Loss Costs (Millions)									
	DEC			INC			Up to Congestion			
	Day-Ahead	Balancing	Total	Day-Ahead	Balancing	Total	Day-Ahead	Balancing	Total	Grand Total
Jan	($0.6)	($0.0)	($0.6)	$1.5	($1.3)	$0.2	$6.7	($13.4)	($6.7)	($7.1)
Feb	($0.6)	$0.4	($0.2)	$1.3	($1.1)	$0.2	$5.3	($7.7)	($2.4)	($2.4)
Mar	($1.1)	$0.7	($0.4)	$2.6	($2.0)	$0.6	$5.3	($8.1)	($2.8)	($2.6)
Apr	($1.1)	$1.0	($0.0)	$0.8	($0.9)	($0.1)	$4.5	($6.8)	($2.3)	($2.4)
May	($1.3)	$1.1	($0.2)	$1.6	($1.3)	$0.2	$4.3	($6.4)	($2.1)	($2.1)
Jun	($0.8)	$0.8	($0.0)	$1.1	($0.9)	$0.3	$3.8	($5.8)	($2.0)	($1.7)
Jul	($1.0)	$0.9	($0.1)	$1.4	($0.9)	$0.4	$5.1	($8.0)	($2.9)	($2.7)
Aug	($0.3)	$0.3	($0.0)	$0.6	($0.6)	$0.0	$5.0	($7.8)	($2.8)	($2.8)
Sep	($0.4)	$0.5	$0.1	$1.0	($1.1)	($0.1)	$2.9	($7.4)	($4.4)	($4.4)
Oct	($0.2)	$0.4	$0.1	$0.8	($0.9)	($0.1)	$3.6	($5.9)	($2.2)	($2.2)
Nov	($0.3)	$0.2	($0.0)	$0.7	($0.7)	$0.0	$3.8	($5.4)	($1.6)	($1.6)
Dec	($0.1)	($0.2)	($0.3)	$0.4	($0.3)	$0.1	$4.6	($7.4)	($2.8)	($3.0)
Total	($7.7)	$6.0	($1.7)	$13.8	($12.0)	$1.8	$54.9	($90.0)	($35.1)	($35.1)

Marginal Loss Costs and Loss Credits

Total loss surplus are calculated by adding the total energy costs, the total marginal loss costs and net residual market adjustments. The total energy costs are equal to the net implicit energy costs (load energy payments minus generation energy credits) plus net explicit energy costs plus net inadvertent energy charges. Total marginal loss costs are equal to the net implicit marginal loss costs (generation loss credits less load loss payments) plus net explicit loss costs plus net inadvertent loss charges.

Ignoring interchange, total generation MWh must be greater than total load MWh in any hour in order to provide for losses. Since the hourly integrated energy component of LMP is the same for every bus within every hour, the net energy bill is negative (ignoring net interchange), with more generation credits than load payments in every hour. Total energy costs plus total marginal loss costs plus net residual market adjustments equal marginal loss credits which are distributed to the PJM market participants according to the ratio of their real-time load plus their real-time exports to total PJM real-time load plus real-time exports as marginal loss credits. The net residual market adjustment is calculated as known day-ahead error value minus day-ahead loss MW congestion value and minus balancing loss MW congestion value.

Table 11-67 Marginal loss surplus (Dollars (Millions)): 2008 through 2018[36]

	Marginal Loss Surplus (Millions)					
			Net Residual Market Adjustment			
	Total Energy Charges	Total Marginal Loss Charges	Known Day-Ahead Error	Day-Ahead Loss MW Congestion	Balancing Loss MW Congestion	Total
2008	($1,193.2)	$2,496.7	$0.0	$0.0	$0.0	$1,303.5
2009	($628.8)	$1,267.7	$0.0	($0.7)	($0.0)	$639.7
2010	($797.9)	$1,634.8	$0.1	$0.7	($0.0)	$836.4
2011	($793.8)	$1,379.5	$0.1	($1.0)	$0.1	$586.7
2012	($593.0)	$981.7	$0.0	$2.0	($0.0)	$386.7
2013	($687.6)	$1,035.3	$0.1	$3.0	($0.0)	$344.8
2014	($977.7)	$1,466.1	($0.0)	$6.3	$0.1	$482.1
2015	($627.4)	$968.7	($0.0)	$5.1	($0.1)	$336.3
2016	($466.3)	$696.5	($0.0)	$3.2	($0.2)	$227.2
2017	($475.2)	$690.8	$0.0	$1.1	($0.1)	$214.6
2018	($636.7)	$960.1	($0.0)	$3.2	($0.1)	$320.2

Table 11-67 shows the total energy costs, the total marginal loss costs collected, the net residual market adjustments and total marginal loss surplus redistributed for 2008 through 2018. The total marginal loss surplus increased $105.6 million in 2018 from 2017.

Energy Costs

Energy Accounting

The energy component of LMP is the system reference bus LMP, also called the system marginal price (SMP). The energy cost is based on the day-ahead and real-time energy components of LMP. Total energy costs, analogous to total congestion costs or total loss costs, are equal to the load energy payments minus generation energy credits, plus explicit energy costs, incurred in both the Day-Ahead Energy Market and the balancing energy market, plus net inadvertent energy charges. Total energy costs can be more accurately thought of as net energy costs.

Total Energy Costs

The total energy cost for 2018 was -$636.7 million, which was comprised of load energy payments of $43,803.7 million, generation energy credits of $44,445.1 million, explicit energy costs of $0.0 million and inadvertent energy charges of $4.6 million. The monthly energy costs for 2018 ranged from -$150.9 million in January to -$33.6 million in February.

36 The net residual market adjustments included in the table are comprised of the known day-ahead error value minus the sum of the day-ahead loss MW congestion value, balancing loss MW congestion value and measurement error caused by missing data.

Table 11-68 shows total energy component costs and total PJM billing, for 2008 through 2018. The total energy component costs are net energy costs.

Table 11-68 Total PJM energy component costs (Dollars (Millions)): 2008 through 2018[37]

	Energy Costs	Percent Change	Total PJM Billing	Percent of PJM Billing
2008	($1,193)	NA	$34,306	(3.5%)
2009	($629)	(47.3%)	$26,550	(2.4%)
2010	($798)	26.9%	$34,771	(2.3%)
2011	($794)	(0.5%)	$35,887	(2.2%)
2012	($593)	(25.3%)	$29,181	(2.0%)
2013	($688)	15.9%	$33,860	(2.0%)
2014	($978)	42.2%	$50,030	(2.0%)
2015	($627)	(35.8%)	$42,630	(1.5%)
2016	($466)	(25.7%)	$39,050	(1.2%)
2017	($475)	1.9%	$40,170	(1.2%)
2018	($637)	34.0%	$49,790	(1.3%)

Energy costs for 2008 through 2018 are shown in Table 11-69 and Table 11-70. Table 11-69 shows PJM energy costs by accounting category and Table 11-70 shows PJM energy costs by market category.

Table 11-69 Total PJM energy costs by accounting category (Dollars (Millions)): 2008 through 2018

	Energy Costs (Millions)				
	Load Payments	Generation Credits	Explicit Costs	Inadvertent Charges	Total
2008	$105,665.6	$106,860.0	$0.0	$1.2	($1,193.2)
2009	$42,535.2	$43,165.7	$0.0	$1.7	($628.8)
2010	$53,101.5	$53,886.9	$0.0	($12.6)	($797.9)
2011	$47,658.9	$48,481.0	$0.0	$28.3	($793.8)
2012	$37,471.3	$38,073.5	$0.0	$9.1	($593.0)
2013	$42,774.3	$43,454.6	$0.0	($7.4)	($687.6)
2014	$60,258.5	$61,232.0	$0.0	($4.2)	($977.7)
2015	$40,601.8	$41,231.9	$0.0	$2.7	($627.4)
2016	$34,053.6	$34,510.1	$0.0	($9.8)	($466.3)
2017	$35,152.1	$35,634.4	$0.0	$7.1	($475.2)
2018	$43,803.7	$44,445.1	$0.0	$4.6	($636.7)

Table 11-70 Total PJM energy costs by market category (Dollars (Millions)): 2008 through 2018

	Energy Costs (Millions)									
	Day-Ahead				Balancing					
	Load Payments	Generation Credits	Explicit Costs	Total	Load Payments	Generation Credits	Explicit Costs	Total	Inadvertent Charges	Grand Total
2008	$81,789.8	$83,120.0	$0.0	($1,330.1)	$23,875.8	$23,740.0	$0.0	$135.7	$1.2	($1,193.2)
2009	$42,683.8	$43,351.2	$0.0	($667.4)	($148.5)	($185.5)	$0.0	$36.9	$1.7	($628.8)
2010	$53,164.9	$53,979.1	$0.0	($814.1)	($63.4)	($92.2)	$0.0	$28.8	($12.6)	($797.9)
2011	$48,144.9	$48,880.0	$0.0	($735.2)	($485.9)	($399.1)	$0.0	($86.9)	$28.3	($793.8)
2012	$37,641.2	$38,251.1	$0.0	($609.9)	($169.9)	($177.6)	$0.0	$7.7	$9.1	($593.0)
2013	$42,795.2	$43,628.9	$0.0	($833.7)	($20.9)	($174.4)	$0.0	$153.5	($7.4)	($687.6)
2014	$60,325.2	$61,668.9	$0.0	($1,343.7)	($66.7)	($436.9)	$0.0	$370.2	($4.2)	($977.7)
2015	$40,837.8	$41,595.7	$0.0	($757.9)	($236.0)	($363.8)	$0.0	$127.8	$2.7	($627.4)
2016	$34,245.1	$34,885.7	$0.0	($640.6)	($191.5)	($375.6)	$0.0	$184.0	($9.8)	($466.3)
2017	$35,490.1	$36,138.6	$0.0	($648.5)	($338.0)	($504.2)	$0.0	$166.2	$7.1	($475.2)
2018	$43,947.9	$44,658.9	$0.0	($711.0)	($144.1)	($213.8)	$0.0	$69.7	$4.6	($636.7)

Table 11-71 and Table 11-72 show the total energy costs for each transaction type in 2018 and 2017. In 2018, generation was paid $31,247.1 million and demand paid $30,094.5 million in net energy payment. In 2017, generation was paid $24,566.8 million and demand paid $23,484.2 million in net energy payment.

37 The energy costs include net inadvertent charges.

Table 11-71 Total PJM energy costs by transaction type by market (Dollars (Millions)): 2018

	Energy Costs (Millions)								
	Day-Ahead				Balancing				
Transaction Type	Load Payments	Generation Credits	Explicit Costs	Total	Load Payments	Generation Credits	Explicit Costs	Total	Grand Total
DEC	$1,010.9	$0.0	$0.0	$1,010.9	($1,019.5)	$0.0	$0.0	($1,019.5)	($8.6)
Demand	$29,631.7	$0.0	$0.0	$29,631.7	$462.9	$0.0	$0.0	$462.9	$30,094.5
Demand Response	($1.0)	$0.0	$0.0	($1.0)	$1.0	$0.0	$0.0	$1.0	$0.0
Export	$858.4	$0.0	$0.0	$858.4	$386.7	$0.0	$0.0	$386.7	$1,245.1
Generation	$0.0	$31,211.7	$0.0	($31,211.7)	$0.0	$35.3	$0.0	($35.3)	($31,247.1)
Import	$0.0	$139.1	$0.0	($139.1)	$0.0	$579.1	$0.0	($579.1)	($718.2)
INC	$0.0	$860.1	$0.0	($860.1)	$0.0	($853.0)	$0.0	$853.0	($7.1)
Internal Bilateral	$12,448.0	$12,448.0	$0.0	($0.0)	$14.8	$14.8	$0.0	($0.0)	($0.0)
Wheel In	$0.0	$0.0	$0.0	$0.0	$0.0	$9.9	$0.0	($9.9)	($9.9)
Wheel Out	$0.0	$0.0	$0.0	$0.0	$9.9	$0.0	$0.0	$9.9	$9.9
Total	$43,947.9	$44,658.9	$0.0	($711.0)	($144.1)	($213.8)	$0.0	$69.7	($641.3)

Table 11-72 Total PJM energy costs by transaction type by market (Dollars (Millions)): 2017

	Energy Costs (Millions)								
	Day-Ahead				Balancing				
Transaction Type	Load Payments	Generation Credits	Explicit Costs	Total	Load Payments	Generation Credits	Explicit Costs	Total	Grand Total
DEC	$1,092.8	$0.0	$0.0	$1,092.8	($1,095.6)	$0.0	$0.0	($1,095.6)	($2.9)
Demand	$23,433.7	$0.0	$0.0	$23,433.7	$50.5	$0.0	$0.0	$50.5	$23,484.2
Demand Response	($0.6)	$0.0	$0.0	($0.6)	$0.6	$0.0	$0.0	$0.6	($0.0)
Export	$707.1	$0.0	$0.0	$707.1	$346.6	$0.0	$0.0	$346.6	$1,053.6
Generation	$0.0	$24,616.7	$0.0	($24,616.7)	$0.0	($50.0)	$0.0	$50.0	($24,566.8)
Import	$0.0	$81.2	$0.0	($81.2)	$0.0	$361.0	$0.0	($361.0)	($442.2)
INC	$0.0	$1,183.6	$0.0	($1,183.6)	$0.0	($1,175.3)	$0.0	$1,175.3	($8.2)
Internal Bilateral	$10,257.2	$10,257.2	$0.0	$0.0	$359.9	$359.9	$0.0	$0.0	$0.0
Total	$35,490.1	$36,138.8	$0.0	($648.7)	($338.0)	($504.4)	$0.0	$166.4	($482.3)

Monthly Energy Costs

Table 11-73 shows a monthly summary of energy costs by market type for 2017 and 2018. Marginal total energy costs in 2018 decreased from 2017. Monthly total energy costs in 2018 ranged from -$150.9 million in January to -$33.6 million in February.

Table 11-73 Monthly energy costs by market type (Dollars (Millions)): 2017 and 2018

	Energy Costs (Millions)							
	2017				2018			
	Day-Ahead Total	Balancing Total	Inadvertent Charges	Grand Total	Day-Ahead Total	Balancing Total	Inadvertent Charges	Grand Total
Jan	($75.6)	$28.9	($1.5)	($48.2)	($160.3)	$4.9	$4.6	($150.9)
Feb	($48.3)	$16.5	$0.0	($31.8)	($41.2)	$7.4	$0.1	($33.6)
Mar	($59.9)	$17.5	$0.2	($42.2)	($45.0)	$2.9	$0.1	($42.1)
Apr	($46.7)	$15.2	$0.5	($31.0)	($40.4)	$2.6	($0.0)	($37.8)
May	($46.2)	$12.6	$1.0	($32.6)	($46.5)	$5.4	$0.3	($40.8)
Jun	($45.8)	$8.6	$0.7	($36.4)	($47.0)	$7.2	($0.1)	($39.9)
Jul	($61.3)	$14.7	$1.2	($45.4)	($59.6)	$5.7	$0.5	($53.5)
Aug	($52.7)	$12.8	$1.1	($38.9)	($60.7)	$5.7	$0.3	($54.6)
Sep	($47.9)	$9.0	$1.3	($37.5)	($50.8)	$5.3	($0.0)	($45.4)
Oct	($43.7)	$8.2	$1.7	($33.8)	($47.2)	$4.5	($0.6)	($43.2)
Nov	($45.4)	$9.7	$0.1	($35.5)	($57.2)	$9.8	($0.2)	($47.6)
Dec	($75.1)	$12.4	$0.8	($61.9)	($55.2)	$8.3	($0.4)	($47.2)
Total	($648.5)	$166.2	$7.1	($475.2)	($711.0)	$69.7	$4.6	($636.7)

Figure 11-8 shows PJM monthly energy costs for 2008 through 2018.

Figure 11-8 PJM monthly energy costs (Millions): 2008 through 2018

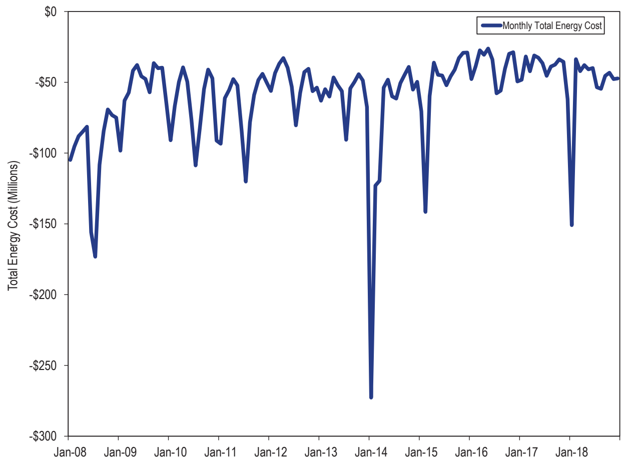


Table 11-74 and Table 11-75 show the monthly total energy costs for each virtual transaction type in 2018 and year of 2017. In 2018, DECs paid $1,010.9 million in energy costs in the day-ahead market, were paid $1,019.5 million in energy credits in the balancing energy market and were paid $8.6 million in total energy credits. In 2018, INCs were paid $860.1 million in energy credits in the day-ahead market, paid $853.0 million in energy costs in the balancing market and were paid $7.1 million in total energy credits. In 2017, DECs paid $1,092.8 million in energy costs in the day-ahead market, were paid $1,095.6 million in energy credits in the balancing energy market and were paid $2.9 million in total energy credits. In 2017, INCs were paid $1,183.6 million in energy credits in the day-ahead market, paid $1,175.3 million in energy cost in the balancing energy market and received $8.2 million in total energy credits.

Table 11-74 Monthly PJM energy costs by virtual transaction type and by market (Dollars (Millions)): 2018

	Energy Costs (Millions)						
	DEC			INC			
	Day-Ahead	Balancing	Total	Day-Ahead	Balancing	Total	Grand Total
Jan	$172.4	($183.2)	($10.8)	($136.9)	$138.3	$1.4	($9.4)
Feb	$47.3	($45.1)	$2.2	($46.3)	$44.2	($2.1)	$0.1
Mar	$65.6	($67.2)	($1.6)	($66.0)	$66.5	$0.4	($1.2)
Apr	$66.2	($67.6)	($1.4)	($76.3)	$76.8	$0.5	($0.9)
May	$86.7	($94.7)	($8.0)	($73.7)	$78.0	$4.3	($3.7)
Jun	$77.1	($74.5)	$2.6	($53.8)	$52.7	($1.0)	$1.6
Jul	$76.5	($71.6)	$4.9	($48.7)	$43.9	($4.7)	$0.2
Aug	$75.8	($75.3)	$0.6	($57.4)	$57.4	($0.0)	$0.6
Sep	$94.5	($98.5)	($4.0)	($65.6)	$67.4	$1.8	($2.2)
Oct	$86.7	($82.4)	$4.3	($85.8)	$82.1	($3.7)	$0.6
Nov	$83.1	($80.9)	$2.2	($88.9)	$86.6	($2.3)	($0.2)
Dec	$79.0	($78.4)	$0.6	($60.8)	$59.2	($1.6)	($1.0)
Total	$1,010.9	($1,019.5)	($8.6)	($860.1)	$853.0	($7.1)	($15.7)

Table 11-75 Monthly PJM energy costs by virtual transaction type and by market (Dollars (Millions)): 2017

	Energy Costs (Millions)						
	DEC			INC			
	Day-Ahead	Balancing	Total	Day-Ahead	Balancing	Total	Grand Total
Jan	$115.3	($116.4)	($1.1)	($134.8)	$135.6	$0.8	($0.3)
Feb	$82.8	($79.8)	$2.9	($107.0)	$103.3	($3.6)	($0.7)
Mar	$123.9	($124.5)	($0.6)	($150.0)	$149.2	($0.8)	($1.4)
Apr	$109.6	($104.2)	$5.4	($106.8)	$102.0	($4.8)	$0.7
May	$112.6	($114.0)	($1.5)	($123.9)	$124.9	$1.0	($0.4)
Jun	$88.3	($87.2)	$1.1	($77.5)	$76.6	($0.9)	$0.2
Jul	$90.2	($93.2)	($2.9)	($92.9)	$95.0	$2.0	($0.9)
Aug	$68.5	($66.9)	$1.6	($70.2)	$68.5	($1.7)	($0.1)
Sep	$81.6	($88.6)	($7.1)	($72.7)	$73.8	$1.1	($6.0)
Oct	$68.6	($66.5)	$2.1	($83.7)	$81.1	($2.6)	($0.5)
Nov	$59.5	($57.0)	$2.5	($75.3)	$72.7	($2.6)	($0.0)
Dec	$91.9	($97.3)	($5.4)	($88.8)	$92.6	$3.8	($1.6)
Total	$1,092.8	($1,095.6)	($2.9)	($1,183.6)	$1,175.3	($8.2)	($11.1)

Generation and Transmission Planning[1]

Overview

Generation Interconnection Planning

Existing Generation Mix

- As of December 31, 2018, PJM had a total installed capacity of 199,489.0 MW, of which 57,891.9 MW (29.0 percent) are coal fired steam units, 46,207.1 MW (23.2 percent) are combined cycle units and 34,257.6 MW (17.2 percent) are nuclear units. This measure of installed capacity differs from capacity market installed capacity because it includes energy only units, excludes all external units, and uses nameplate values for solar and wind resources.
- The AEP zone has the most total installed capacity of any PJM zone. Of the 199,489.0 MW of PJM total installed capacity, 31,643.0 MW (15.9 percent) are in the AEP Zone, of which 14,727.8 MW (46.5 percent) are coal fired steam units, 6,990.0 MW (22.1 percent) are combined cycle units and 2,071.0 MW (6.5 percent) are nuclear units.
- Pennsylvania has the most total installed capacity of any PJM state. Of the 199,489.0 MW of installed capacity, 44,753.1 MW (22.4 percent) are in Pennsylvania, of which 9,467.7 MW (21.2 percent) are coal fired steam units, 13,656.5 MW (30.5 percent) are combined cycle units and 9,648.8 MW (21.6 percent) are nuclear units.
- Of the 199,489.0 MW of installed capacity, 76,587.5 MW (38.4 percent) are from units older than 40 years, of which 41,426.7 MW (54.1 percent) are coal fired steam units, 16,044.9 MW (20.9 percent) are nuclear units, and 532.0 MW (0.7 percent) are combined cycle units.

Generation Retirements[2]

- There are 44,684.1 MW of generation that have been, or are planned to be, retired between 2011 and 2022, of which 31,621.4 MW (70.8 percent) are coal fired steam units. Coal unit retirements are primarily a result of the inability of coal units to compete with efficient combined cycle units burning low cost gas.
- In 2018, 5,522.7 MW of generation retired. The largest generator that retired in 2018 was the 614.5 MW Oyster Creek Nuclear Generating Station owned by Exelon Corporation and located in the Jersey Central Power and Light (JCPL) Zone. Of the 5,522.7 MW of generation that retired, 2,364.0 MW (42.8 percent) were located in the DAY Zone.
- There are 13,398.0 MW of generation that have requested retirement after December 31, 2018, of which 6,791.0 MW (50.7 percent) are located in the ATSI Zone. Of the ATSI generation requesting retirement, 7,829.3 MW (58.4 percent) are coal fired steam units and 4,716.0 MW (35.2 percent) are nuclear units. The largest generator pending retirement is the 1,240 MW Perry U1 Nuclear Generating Unit located in the ATSI Zone.

Generation Queue[3]

- The total MW in generation queues increased by 41,846.2 MW (57.2 percent) from 73,107.6 MW at the end of 2017 to 114,953.7 MW on December 31, 2018.
- A significant shift in the distribution of unit types within the PJM footprint continues to develop as natural gas fired units enter the queue and coal fired steam units retire. As of December 31, 2018, there were 52,804.2 MW of natural gas fired capacity active, suspended or under construction in PJM queues (including combined cycle units, CTs, RICE units, and natural gas fired steam units). As of December 31, 2018, there were only 147.0 MW of coal fired steam capacity active, suspended or under construction in PJM queues.
- As of December 31, 2018, 4,144 projects, representing 529,165.5 MW, have entered the queue process since its inception in 1998. Of those, 816 projects, representing 61,128.0 MW, went into service. Of the projects that entered the queue process, 2,392 projects, representing 353,083.9 MW (66.7 percent of the MW) withdrew prior to completion. Such projects may create barriers to entry for projects that would otherwise be completed by taking up

1 Totals presented in this section include corrections to historical data and may not match totals presented in previous reports.

2 See PJM "Generator Deactivations," at <http://www.pjm.com/planning/services-requests/gen-deactivations.aspx>.

3 See PJM "New Services Queue," at <https://www.pjm.com/planning/services-requests/interconnection-queues.aspx>.

queue positions, increasing interconnection costs and creating uncertainty.

Regional Transmission Expansion Plan (RTEP)

Backbone Facilities

- There are currently three backbone projects under development, Surry Skiffes Creek 500kV, and the conversion of the Marion-Bayonne and Bayway-Linden lines from 138 kV to 345 kV.[4]

Market Efficiency Process

- PJM's first market efficiency analysis was performed in 2013, prior to Order 1000. This analysis evaluated the reasons for congestion on 25 flowgates.[5] The proposal window was open from August 12, 2013, through September 26, 2013. PJM received 38 proposals from six entities. One project was approved by the PJM Board.
- Through December 31, 2018, PJM has completed two market efficiency cycles under Order No. 1000. In the first cycle, PJM received 93 proposals for 57 identified sources of congestion. In the second cycle, PJM received 96 proposals for four identified sources of congestion. The proposal window for 2018/2019 opened on November 1, 2018, and will close on February 28, 2019.
- Approved market efficiency projects periodically undergo a reevaluation process to ensure that the benefit/cost ratio continues to meet the 1.25:1 threshold. The Transource AP-South project was reevaluated in September 2017, February 2018, and again in September 2018. The project exceeded the 1.25:1 threshold in all reevaluations.
- There are significant issues with PJM's benefit/cost analysis that should be addressed prior to approval of additional projects.

PJM MISO Interregional Targeted Market Efficiency Process (TMEP)

- The first Targeted Market Efficiency Process (TMEP) analysis occurred in 2017 and included the investigation of congestion on 50 market to market flowgates. The study resulted in the evaluation of 13 potential upgrades, resulting in the recommendation of five TMEP projects. The five projects address $59 million in historical congestion, with a TMEP benefit of $99.6 million. The projects have a total cost of $20 million, with a 5.0 average benefit/cost ratio. PJM and MISO presented the five recommended projects to their boards in December, 2017, and both boards approved all five projects.[6]
- The 2018 TMEP analysis included the investigation of congestion on 61 market to market flowgates. The study resulted in the evaluation of 19 potential upgrades, resulting in the recommendation of two TMEP projects. The two projects address $25 million in historical congestion, with a TMEP benefit of $31.9 million. The projects have a total cost of $4.5 million, with a 7.1 average benefit/cost ratio. PJM and MISO presented the two recommended projects to their boards in December, 2018, and both boards approved the projects.[7]

Supplemental Transmission Projects

- Supplemental projects are "transmission expansions or enhancements that are not required for compliance with PJM criteria and are not state public policy projects according to the PJM Operating Agreement. These projects are used as inputs to RTEP models, but are not required for reliability, economic efficiency or operational performance criteria, as determined by PJM."[8] Supplemental projects are exempt from the competitive planning process.
- The average number of supplemental projects in each expected in service year increased by 520.0 percent, from 20 for years 1998 through 2007 (pre Order 890) to 124 for years 2008 through 2018 (post Order 890).

4 See "2017 RTEP Process Scope and Input Assumptions White Paper," at 25. <http://www.pjm.com/-/media/library/reports-notices/2017-rtep/20170731-rtep-input-assumptions-and-scope-whitepaper.ashx?la=en>.

5 Historical congestion drivers are identified using the historical congestion tables presented in the 2018 *State of the Market Report for PJM*, Section 11: Congestion and Marginal Losses, historical analysis of real time constraints, the NERC Book of Flowgates and PROMOD simulations.

6 See PJM, "*MISO PJM IPSAC*" (January 12, 2018) <http://www.pjm.com/-/media/committees-groups/stakeholder-meetings/ipsac/20180112/20180112-ipsac-presentation.ashx>.

7 See PJM, "*MISO PJM IPSAC*," (January 18, 2019) <https://www.pjm.com/-/media/committees-groups/stakeholder-meetings/ipsac/20190118/20190118-ipsac-presentation.ashx>.

8 See PJM, "*Transmission Construction Status*," (January 23, 2018) <http://www.pjm.com/planning/rtep-upgrades-status/construct-status.aspx>.

End of Life Transmission Projects

- An end of life transmission project is a project submitted for the purpose of replacing existing infrastructure that is at, or is approaching, the end of its useful life. End of life transmission projects fall under the Transmission Owner Form 715 Planning Criteria, and are currently exempt from the competitive planning process.[9] End of life transmission projects are already included in the supplemental projects totals or, if included in the transmission owners' reliability plan, will be included in the baseline project list as a reliability criteria project.
- End of life transmission projects should be subject to a transparent, robust and clearly defined mechanism to permit competition to build the project.

Board Authorized Transmission Upgrades

- The Transmission Expansion Advisory Committee (TEAC) reviews internal and external proposals to improve transmission reliability throughout PJM. These proposals, which include reliability baseline, network, market efficiency and targeted market efficiency projects, but exclude supplemental and end of life projects, are periodically presented to the PJM Board of Managers for authorization.[10] In 2018, the PJM Board approved $1.98 billion in upgrades. As of December 31, 2018, the PJM Board has approved $37.1 billion in system enhancements since 1999

Transmission Competition

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

Qualifying Transmission Upgrades (QTU)

- A Qualifying Transmission Upgrade (QTU) is an upgrade to the transmission system that increases the Capacity Emergency Transfer Limit into an LDA and can be offered into capacity auctions as capacity.
- QTU projects are submitted and tracked through the PJM queue.[11] A total of 51 QTU projects have entered the queue since 2007. Of the 51 submitted QTU projects, 37 projects (72.5 percent) have been withdrawn, five (10.0 percent) are in service and nine (17.5 percent) are currently in active development.

Transmission Facility Outages

- PJM maintains a list of reportable transmission facilities. When the reportable transmission facilities need to be taken out of service, PJM transmission owners are required to report planned transmission facility outages as early as possible. PJM processes the transmission facility outage requests according to rules in PJM's Manual 3 to decide if the outage is on time or late and whether or not they will allow the outage.[12]
- There were 16,790 transmission outage requests submitted in the 2018/2019 planning period. Of the requested outages, 74.4 percent of the requested outages were planned for less than or equal to five days and 8.8 percent of requested outages were planned for greater than 30 days. Of the requested outages, 42.8 percent were late according to the rules in PJM's Manual 3.

9 See PJM Operating Agreement Schedule 6 § 1.5.8(o).
10 Supplemental Projects, including the end of life subset of supplemental projects, do not require PJM Board of Managers authorization.
11 See PJM "New Services Queue," at <https://www.pjm.com/planning/services-requests/interconnection-queues.aspx>.
12 PJM, "Manual 03: Transmission Operations," Rev. 54 (Dec. 10, 2018).

Recommendations

The MMU recommends improvements to the planning process:

Generation Retirements

- The MMU recommends that the question of whether Capacity Injection Rights (CIRs) should persist after the retirement of a unit, or the conversion from CP to energy only status, be addressed. The rules need to ensure that incumbents cannot exploit control of CIRs to block or postpone entry of competitors.[13] (Priority: Low. First reported 2013. Status: Not adopted.)
- 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. (Priority: Low. New recommendation. Status: Not adopted.)

Generation Queue

- The MMU recommends that barriers to entry be addressed in a timely manner in order to help ensure that the capacity market will result in the entry of new capacity to meet the needs of PJM market participants and reflect the uncertainty and resultant risks in the cost of new entry used to establish the capacity market demand curve in RPM. (Priority: Low. First reported 2012. Status: Not adopted.)
- The MMU recommends improvements in queue management including that PJM establish a review process to ensure that projects are removed from the queue if they are not viable, as well as a process to allow commercially viable projects to advance in the queue ahead of projects which have failed to make progress, subject to rules to prevent gaming. (Priority: Medium. First reported 2013. Status: Partially adopted.)
- The MMU recommends continuing analysis of the study phase of PJM's transmission planning to reduce the need for postponements of study results, to decrease study completion times, and to improve the likelihood that a project at a given phase in the study process will successfully go into service. (Priority: Medium. First reported 2014. Status: Partially adopted.)
- The MMU recommends outsourcing interconnection studies to an independent party to avoid potential conflicts of interest. Currently, these studies are performed by incumbent transmission owners under PJM's direction. This creates potential conflicts of interest, particularly when transmission owners are vertically integrated and the owner of transmission also owns generation. (Priority: Low. First reported 2013. Status: Not adopted.)

Market Efficiency Process

- The MMU recommends that 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. (Priority: Medium. First reported Q3, 2018. Status: Not adopted.)
- 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. (Priority: Medium. New recommendation. Status: Not adopted.)

Supplemental Transmission Projects

- 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. (Priority: Medium. First reported 2017. Status: Not adopted.)

Transmission Competition

- 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

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

transmission. (Priority: Medium. First reported 2015. Status: Not adopted.)

- The MMU recommends that PJM continue to incorporate the principle that the goal of transmission planning should be the incorporation of transmission investment decisions into market driven processes as much as possible. (Priority: Low. First reported 2001. Status: Not adopted.)
- The MMU recommends the creation of a mechanism to permit a direct comparison, or competition, between transmission and generation alternatives, including which alternative is less costly and who bears the risks associated with each alternative. (Priority: Low. First reported 2013. Status: Not adopted.)
- The MMU recommends that PJM establish fair terms of access to rights of way and property, such as at substations, in order to remove any barriers to entry and permit competition between incumbent transmission providers and merchant transmission providers in the RTEP. (Priority: Medium. First reported 2014. Status: Not adopted.)
- The MMU recommends that rules be implemented to permit competition to provide financing for transmission projects. This competition could reduce the cost of capital for transmission projects and significantly reduce total costs to customers. (Priority: Low. First reported 2013. Status: Not adopted.)
- The MMU recommends that rules be implemented to require that project cost caps on new transmission projects be part of the evaluation of competing projects. (Priority: Medium. First reported 2015. Status: Not adopted.)

Transmission Facility Outages

- 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.[14] (Priority: Medium. First reported 2015. Status: Not adopted.)
- The MMU recommends that PJM reevaluate all transmission outage tickets as on time or late as if they were new requests when an outage is rescheduled and apply the standard rules for late submissions to any such outages. (Priority: Low. First reported 2014. Status: Not adopted.)
- The MMU recommends that PJM draft a clear definition of the congestion analysis required for transmission outage requests to include in Manual 3 after appropriate review. (Priority: Low. First reported 2015. Status: Not adopted.)
- 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. (Priority: Low. First reported 2015. Status: Not adopted.)
- The MMU recommends that PJM not permit transmission owners to divide long duration outages into smaller segments to avoid complying with the requirements for long duration outages. (Priority: Low. First reported 2015. Status: Not adopted.)

Conclusion

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

The addition of a planned transmission project changes the parameters of the capacity auction for the area, changes the amount of capacity needed in the area, changes the capacity market supply and demand fundamentals in the area and may effectively forestall the ability of generation to compete. But there is no mechanism to permit a direct comparison, let alone competition, between transmission and generation alternatives. There is no mechanism to evaluate whether

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

the generation or transmission alternative is less costly, whether there is more risk associated with the generation or transmission alternatives, or who bears the risks associated with each alternative. Creating such a mechanism should be an explicit goal of PJM market design.

Managing the generation queues is a highly complex process. The PJM queue evaluation process has been substantially improved in recent years and it is more efficient and effective as a result. The PJM queue evaluation process should continue to be improved to help ensure that barriers to competition for new generation investments are not created. Issues that need to be addressed include the ownership rights to CIRs, whether transmission owners should perform interconnection studies, and improvements in queue management 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.

The PJM rules for competitive transmission development through the RTEP should build upon FERC Order No. 1000 to create real competition between incumbent transmission providers and merchant transmission providers. The ability of transmission owners to block competition for supplemental projects and end of life projects and reasons for that policy should be reevaluated. PJM should 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. Another element of opening competition would be to consider transmission owners' ownership of property and rights of way at or around transmission substations. In many cases, the land acquired included property intended to support future expansion of the grid. Incumbents have included the costs of the property in their rate base. Because PJM now has the responsibility for planning the development of the grid under its RTEP process, property bought to facilitate future expansion should be a part of the RTEP process and be made available to all providers on equal terms.

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

The inclusion of market efficiency transmission projects in the transmission planning process, in addition to reliability projects, effectively results in direct competition between generation and transmission to address congestion issues in the wholesale power market, including congestion in the energy and capacity markets. The role of the market efficiency process and its impact on competition should be more thoroughly evaluated. But PJM fails to explicitly address this fact in the design of the market efficiency process. While the market efficiency process and metrics require improvement, for example to ensure that all congestion is measured, the role of the market efficiency process and its impact on competition should also be more thoroughly evaluated. Building transmission under cost of service regulation already provides a significant competitive advantage to transmission over generation which is built entirely based on market prices and for which investors take the risks. The risks of cost increases for transmission projects should be incorporated in the cost benefit analysis.

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

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

The current rules governing the benefit/cost analysis evaluate competing projects with different in service dates on an asymmetric basis. Under the current rules, projects are evaluated on a present value, benefit/cost basis over a 15 year service horizon, starting with the in service date of the project. A better approach would be to establish a common end date for all evaluated competing projects so that the minimum included years for any evaluated project was 15 years. This means that if there were an RTEP year zero project and a RTEP year +2 project competing, the benefit/cost ratio analysis would include the benefits and costs for both projects for every year from RTEP year zero to RTEP+16. Under this approach all projects would be evaluated over an identical term rather than an artificially truncated term and all projects would be evaluated on a present value basis at year zero.[15]

There are currently no market incentives for transmission owners to submit and complete transmission outages in a timely and efficient manner. Requiring transmission owners to pay does not create an effective incentive when those payments are passed through to transmission customers. The process for the submission of planned transmission outages needs to be carefully reviewed and redesigned to limit the ability of transmission owners to submit transmission outages that are late for FTR auction bid submission dates and are late for the Day-Ahead Energy Market. The submission of late transmission outages can inappropriately affect market outcomes when market participants do not have the ability to modify market bids and offers.

Generation Interconnection Planning

Existing Generation Mix

Table 12-1 shows the existing PJM capacity by control zone and unit type.[16] As of December 31, 2018, PJM had an installed capacity of 199,489.0 MW, of which 57,891.9 MW (29.0 percent) are coal fired steam units, 46,207.1 MW (23.2 percent) are combined cycle units and 34,257.6 MW (17.2 percent) are nuclear units. This measure of installed capacity differs from capacity market installed capacity because it includes energy only units, excludes all external units, and uses nameplate values for solar and wind resources.

The AEP Zone has the most total installed capacity of any PJM zone. Of the 199,489.0 MW of PJM total installed capacity, 31,643.0 MW (15.9 percent) are in the AEP Zone, of which 14,727.8 MW (46.5 percent) are coal fired steam units, 6,990.0 MW (22.1 percent) are combined cycle units and 2,071.0 MW (6.5 percent) are nuclear units.

15 See "Comments of the Independent Market Monitor for PJM," (January 11, 2019) <http://www.monitoringanalytics.com/Filings/2019/IMM_Comments_Docket_No_ER19-80_20190111.pdf>.
16 The unit type RICE refers to Reciprocating Internal Combustion Engines.

Table 12-1 Existing PJM capacity: December 31, 2018 (By zone and unit type (MW))[17]

Zone	Battery	Combined Cycle	CT - Natural Gas	CT - Oil	CT - Other	Fuel Cell	Hydro - Pumped Storage	Hydro - Run of River	Nuclear	RICE - Natural Gas	RICE - Oil	RICE - Other	Solar	Steam - Coal	Steam - Natural Gas	Steam - Oil	Steam - Other	Wind	Total
AECO	0.0	901.9	544.7	0.0	26.0	1.6	0.0	0.0	0.0	0.0	4.0	10.6	59.4	613.9	0.0	0.0	0.0	7.5	2,169.5
AEP	6.0	6,990.0	3,661.2	0.0	21.0	0.0	66.0	486.9	2,071.0	0.0	0.0	20.4	14.7	14,727.8	738.0	0.0	50.0	2,790.0	31,643.0
APS	80.4	2,179.0	1,223.3	0.0	2.0	0.0	0.0	129.2	0.0	0.0	29.6	18.3	55.1	5,409.0	0.0	0.0	0.0	1,191.5	10,317.4
ATSI	0.0	2,150.5	958.0	0.0	659.4	0.0	0.0	0.0	2,134.0	0.0	18.5	46.1	0.0	5,394.0	325.0	0.0	0.0	0.0	11,685.5
BGE	0.0	0.0	500.1	0.0	267.8	0.0	0.0	0.4	1,716.0	0.0	0.0	7.2	1.1	1,713.0	240.5	397.0	57.0	0.0	4,900.1
ComEd	148.5	2,621.1	6,969.3	0.0	226.2	0.0	0.0	0.0	10,473.5	0.0	0.0	38.3	9.0	4,124.1	1,326.0	0.0	0.0	3,584.9	29,520.9
DAY	0.0	0.0	1,344.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	34.0	4.5	1.1	0.0	0.0	0.0	0.0	0.0	1,384.1
DEOK	20.0	522.2	598.0	0.0	56.0	0.0	0.0	112.0	0.0	0.0	0.0	4.8	0.0	1,857.0	47.0	0.0	0.0	0.0	3,217.0
DLCO	0.0	244.0	0.0	0.0	15.0	0.0	0.0	6.3	1,777.0	0.0	0.0	0.0	0.0	565.0	0.0	0.0	0.0	0.0	2,607.3
Dominion	0.0	9,099.6	3,835.3	0.0	266.4	0.0	3,003.0	586.3	3,581.3	0.0	39.0	112.8	622.3	4,705.6	351.0	1,586.0	368.4	208.0	28,365.0
DPL	0.0	1,742.5	1,298.2	0.0	478.2	30.0	0.0	0.0	0.0	0.0	88.0	14.1	213.4	410.0	882.0	153.0	0.0	0.0	5,309.4
EKPC	0.0	0.0	774.0	0.0	0.0	0.0	0.0	70.0	0.0	0.0	0.0	0.0	0.0	1,687.0	0.0	0.0	0.0	0.0	2,531.0
JCPL	20.0	2,402.5	531.1	0.0	232.0	0.4	400.0	0.0	0.0	0.0	0.0	16.1	287.4	0.0	0.0	0.0	10.0	0.0	3,899.6
Met-Ed	0.0	1,616.0	2.0	0.0	398.5	0.0	0.0	19.0	805.0	0.0	0.0	33.4	0.0	115.0	0.0	0.0	60.0	0.0	3,048.9
OVEC	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2,388.8	0.0	0.0	0.0	0.0	2,388.8
PECO	0.0	3,209.0	50.8	0.0	834.0	0.0	1,070.0	572.0	4,546.8	0.0	2.0	0.9	3.0	3.3	762.0	0.0	163.0	0.0	11,216.8
PENELEC	28.4	850.0	350.5	0.0	57.0	0.0	513.0	77.8	0.0	0.0	106.8	17.8	0.0	6,141.5	610.0	0.0	42.0	1,028.8	9,823.6
Pepco	0.0	1,710.0	764.2	0.0	308.0	0.0	0.0	0.0	0.0	0.0	0.0	11.1	0.0	2,433.0	1,164.1	0.0	52.0	0.0	6,442.4
PPL	20.0	5,558.5	252.0	0.0	150.1	0.0	0.0	706.6	2,520.0	0.0	17.0	24.7	15.0	2,642.9	2,449.0	10.0	29.0	216.5	14,611.3
PSEG	5.7	4,410.3	1,039.2	0.0	0.0	0.0	0.0	5.0	3,493.0	0.0	0.0	6.0	195.6	0.0	3.0	0.0	188.1	0.0	9,345.8
XIC	0.0	0.0	691.6	0.0	0.0	0.0	0.0	269.1	1,140.0	0.0	0.0	0.0	0.0	2,961.0	0.0	0.0	0.0	0.0	5,061.7
Total	329.0	46,207.1	25,388.0	0.0	3,997.6	32.0	5,052.0	3,040.6	34,257.6	0.0	338.9	387.0	1,477.1	57,891.9	8,897.6	2,146.0	1,019.5	9,027.2	199,489.0

Table 12-2 shows the installed capacity by state for each fuel type. Pennsylvania has the most total installed capacity of any PJM state. Of the 199,489.0 MW of installed capacity, 44,753.1 MW (22.4 percent) are in Pennsylvania, of which 9,467.7 MW (21.2 percent) are coal fired steam units, 13,656.5 MW (30.5 percent) are combined cycle units and 9,648.8 MW (21.6 percent) are nuclear units.

Table 12-2 Existing PJM capacity: December 31, 2018 (By state and unit type (MW))

State	Battery	Combined Cycle	CT - Natural Gas	CT - Oil	CT - Other	Fuel Cell	Hydro - Pumped Storage	Hydro - Run of River	Nuclear	RICE - Natural Gas	RICE - Oil	RICE - Other	Solar	Steam - Coal	Steam - Natural Gas	Steam - Oil	Steam - Other	Wind	Total
DE	0.0	742.5	325.5	0.0	116.3	30.0	0.0	0.0	0.0	0.0	0.0	8.1	0.0	410.0	882.0	0.0	0.0	0.0	2,514.4
IL	148.5	2,621.1	6,969.3	0.0	226.2	0.0	0.0	0.0	10,473.5	0.0	0.0	38.3	9.0	4,124.1	1,326.0	0.0	0.0	3,584.9	29,520.9
IN	0.0	1,835.0	441.4	0.0	0.0	0.0	0.0	8.2	0.0	0.0	0.0	3.2	10.1	3,923.8	0.0	0.0	0.0	2,023.2	8,244.9
KY	0.0	0.0	1,618.1	0.0	0.0	0.0	0.0	136.0	0.0	0.0	0.0	0.0	0.0	1,687.0	278.0	0.0	0.0	0.0	3,719.1
MD	20.0	2,710.0	2,237.0	0.0	591.7	0.0	0.0	0.4	1,716.0	0.0	76.0	24.3	239.6	4,386.0	1,404.6	550.0	109.0	295.0	14,359.6
MI	0.0	1,200.0	0.0	0.0	4.8	0.0	0.0	11.8	2,071.0	0.0	0.0	3.2	4.6	0.0	0.0	0.0	0.0	0.0	3,295.4
NC	0.0	165.0	0.0	0.0	0.0	0.0	0.0	315.0	0.0	0.0	18.0	0.0	352.7	115.5	0.0	0.0	0.0	208.0	1,174.2
NJ	25.7	7,714.7	2,115.0	0.0	258.0	2.0	400.0	5.0	3,493.0	0.0	4.0	32.7	542.4	613.9	3.0	0.0	198.1	7.5	15,414.9
OH	24.0	6,627.7	4,201.2	0.0	731.6	0.0	0.0	200.0	2,134.0	0.0	52.5	55.4	1.1	14,083.8	372.0	0.0	0.0	766.8	29,250.1
PA	49.9	13,656.5	1,542.7	0.0	1,454.6	0.0	1,583.0	1,445.7	9,648.8	0.0	155.4	95.1	18.0	9,467.7	3,821.0	10.0	294.0	1,510.7	44,753.1
TN	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	50.0	0.0	50.0
VA	0.0	8,934.6	4,172.3	0.0	603.4	0.0	3,069.0	460.1	3,581.3	0.0	33.0	118.8	299.6	3,585.1	811.0	1,586.0	368.4	0.0	27,622.6
WV	60.9	0.0	1,073.9	0.0	11.0	0.0	0.0	189.3	0.0	0.0	0.0	8.0	0.0	12,534.0	0.0	0.0	0.0	631.1	14,508.2
XIC	0.0	0.0	691.6	0.0	0.0	0.0	0.0	269.1	1,140.0	0.0	0.0	0.0	0.0	2,961.0	0.0	0.0	0.0	0.0	5,061.7
Total	329.0	46,207.1	25,388.0	0.0	3,997.6	32.0	5,052.0	3,040.6	34,257.6	0.0	338.9	387.0	1,477.1	57,891.9	8,897.6	2,146.0	1,019.5	9,027.2	199,489.0

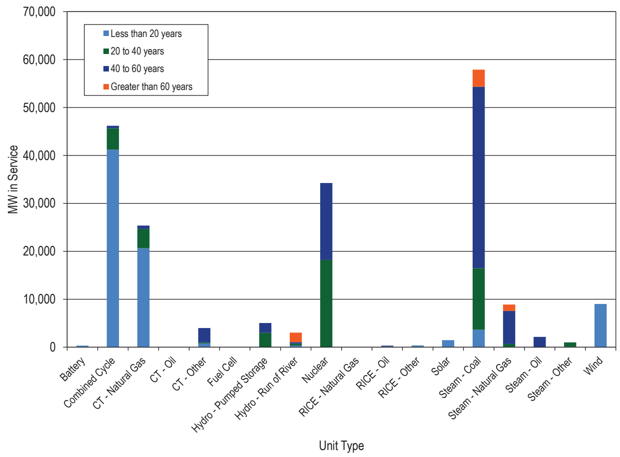
Table 12-3 and Figure 12-1 show the age of existing PJM generators, by unit type, as of December 31, 2018. Of the 199,489.0 MW of installed capacity, 76,587.5 MW (38.4 percent) are from units older than 40 years, of which 41,426.7 MW (54.1 percent) are coal fired steam units, 16,044.9 MW (20.9 percent) are nuclear units, and 532.0 MW (0.7 percent) are combined cycle units.

Table 12-3 PJM capacity (MW) by unit type and age (years): December 31, 2018

Age (years)	Battery	Combined Cycle	CT - Natural Gas	CT - Oil	CT - Other	Fuel Cell	Hydro - Pumped Storage	Hydro - Run of River	Nuclear	RICE - Natural Gas	RICE - Oil	RICE - Other	Solar	Steam - Coal	Steam - Natural Gas	Steam - Oil	Steam - Other	Wind	Total
Less than 20	329.0	41,231.6	20,656.2	0.0	799.0	32.0	0.0	339.2	0.0	0.0	128.4	341.6	1,477.1	3,655.0	82.0	0.0	97.4	9,027.2	78,195.6
20 to 40	0.0	4,443.5	4,029.6	0.0	217.2	0.0	3,003.0	385.2	18,212.7	0.0	37.0	45.4	0.0	12,810.2	600.0	0.0	922.1	0.0	44,705.9
40 to 60	0.0	532.0	702.2	0.0	2,981.4	0.0	2,049.0	340.0	16,044.9	0.0	173.5	0.0	0.0	37,892.4	6,901.1	2,146.0	0.0	0.0	69,762.5
Greater than 60	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1,976.2	0.0	0.0	0.0	0.0	0.0	3,534.3	1,314.5	0.0	0.0	0.0	6,825.0
Total	329.0	46,207.1	25,388.0	0.0	3,997.6	32.0	5,052.0	3,040.6	34,257.6	0.0	338.9	387.0	1,477.1	57,891.9	8,897.6	2,146.0	1,019.5	9,027.2	199,489.0

17 The capacity described in this section refers to all capacity in PJM at the summer installed capacity rating, regardless of whether the capacity entered the RPM Auction. This table previously included external units.

Figure 12-1 PJM capacity (MW) by age (years): December 31, 2018



Generation Retirements[18]

Generating units generally plan to retire when they are not economic and do not expect to be economic. The MMU performs an analysis of the economics of all units that plan to retire in order to verify that the units are not economic and there is no potential exercise of market power through physical withholding that could advantage the owner's portfolio.[19] The definition of economic is that unit net revenues are greater than or equal to the unit's avoidable or going forward costs.

PJM does not have the authority to order generating plants to continue operating. PJM's responsibility is to ensure system reliability. When a unit retirement creates reliability issues based on existing and planned generation facilities and on existing and planned transmission facilities, PJM identifies transmission solutions.[20]

Rules that preserve the Capacity Injection Rights (CIRs) associated with retired units, and with the conversion from CP to energy only status, impose significant costs on new entrants. Currently, CIRs persist for one year if unused, and they can be further extended, at no cost, if assigned to a new project in the interconnection queue at the same point of interconnection.[21] There are currently no rules governing the retention of CIRs when units want to convert to energy only status or require time to upgrade to retain CP status. The rules governing conversion or upgrades should be the same as the rules governing retired units. Reforms that require the holders of CIRs to use or lose them, and/or impose costs to holding or transferring them, could make new entry appropriately more attractive. The economic and policy rationale for extending CIRs for inactive units is not clear. Incumbent providers receive a significant advantage simply by imposing on new entrants the entire cost of system upgrades needed to accommodate new entrants. The policy question of whether CIRs should persist after the retirement of a unit should be addressed. Even if the policy treatment of such CIRs remains unchanged, the rules need to ensure that incumbents cannot exploit control of CIRs to block or postpone entry of competitors.

In May 2012, PJM stakeholders (through the Interconnection Process Senior Task Force (IPSTF)) modified the rules to reduce the length of time for which CIRs are retained by the current owner after unit retirements from three years to one.[22] The MMU recognized the progress made in this rule change, but it did not fully address the issues. The MMU recommends that the question of whether Capacity Injection Rights (CIRs) should persist after the retirement of a unit, or conversion from CP to energy only status, be addressed. The rules need to ensure that incumbents cannot exploit control of CIRs to block or postpone entry of competitors.[23]

Generation Retirements 2011 through 2022

Table 12-4 shows that there are 44,684.1 MW of generation that have been, or are planned to be, retired between 2011 and 2022, of which 31,621.4 MW (70.8 percent) are coal fired steam units. Coal unit retirements are primarily a result of the inability of coal units to compete with efficient combined cycle units burning low cost gas.

18 See PJM, "Generator Deactivations," at <http://www.pjm.com/planning/services-requests/gen-deactivations.aspx>.

19 See OATT Section V and Attachment M–Appendix § IV.

20 See PJM, "Explaining Power Plant Retirements in PJM," at <http://learn.pjm.com/three-priorities/planning-for-the-future/explaining-power-plant-retirements.aspx>.

21 See OATT § 230.3.3.

22 See PJM Interconnection, L.L.C., Docket No. ER12-1177 (Feb. 29, 2012).

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

Table 12-4 Summary of PJM unit retirements by unit type (MW): 2011 through 2022

	Battery	Combined Cycle	CT - Natural Gas	CT - Oil	CT - Other	Fuel Cell	Hydro - Pumped Storage	Hydro - Run of River	Nuclear	RICE - Natural Gas	RICE - Oil	RICE - Other	Solar	Steam - Coal
Retirements 2011	0.0	0.0	0.0	0.0	128.3	0.0	0.0	0.0	0.0	0.0	2.7	0.0	0.0	543.0
Retirements 2012	0.0	0.0	250.0	0.0	240.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	5,907.9
Retirements 2013	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	5.9	7.0	0.0	2,589.9
Retirements 2014	0.0	0.0	136.0	0.0	422.0	0.0	0.0	0.0	0.0	0.0	0.0	15.3	0.0	2,239.0
Retirements 2015	0.0	0.0	1,319.0	0.0	858.2	0.0	0.0	0.0	0.0	0.0	10.3	0.0	0.0	7,064.8
Retirements 2016	0.0	0.0	0.0	0.0	71.0	0.0	0.5	0.0	0.0	0.0	8.0	3.9	0.0	243.0
Retirements 2017	40.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.8	0.0	2,038.0
Retirements 2018	1.0	425.0	0.0	0.0	39.6	0.0	0.0	0.0	614.5	0.0	17.2	6.9	0.0	3,166.5
Planned Retirements (November 2018 and later)	0.0	0.0	579.3	0.0	75.4	0.0	0.0	0.0	4,716.0	0.0	13.0	8.0	0.0	7,829.3
Total	41.0	425.0	2,284.3	0.0	1,834.5	0.0	0.5	0.0	5,330.5	0.0	57.1	41.9	0.0	31,621.4

	Steam - Natural Gas	Steam - Oil	Steam - Other	Wind	Total
Retirements 2011	522.5	0.0	0.0	0.0	1,196.5
Retirements 2012	0.0	548.0	16.0	0.0	6,961.9
Retirements 2013	82.0	166.0	8.0	0.0	2,858.8
Retirements 2014	158.0	0.0	0.0	0.0	2,970.3
Retirements 2015	0.0	0.0	0.0	10.4	9,262.7
Retirements 2016	74.0	0.0	0.0	0.0	400.4
Retirements 2017	34.0	0.0	0.0	0.0	2,112.8
Retirements 2018	996.0	148.0	108.0	0.0	5,522.7
Planned Retirements (November 2018 and later)	97.0	10.0	70.0	0.0	13,398.0
Total	1,963.5	872.0	202.0	10.4	44,684.1

Table 12-5 shows the capacity, average size, and average age of units retiring in PJM, from 2011 through 2022, while Table 12-6 shows these retirements by state. Of the 44,684.1 MW of units that has been, or are planned to be, retired between 2011 and 2022, 31,621.4 MW (70.8 percent) are coal fired steam units. These coal fired steam units have an average age of 52.9 years and an average size of 195.2 MW. Over half of the retiring coal fired steam units, 58.8 percent, are located in either Ohio or Pennsylvania. Retirements have generally consisted of smaller subcritical coal fired steam units and those without adequate environmental controls to remain viable in the future.

Table 12-5 Retirements by unit type: 2011 through 2022

Unit Type	Number of Units	Avg. Size (MW)	Avg. Age at Retirement (Years)	Total MW	Percent
Battery	2	20.5	7.0	41.0	0.1%
Combined Cycle	2	212.5	25.5	425.0	1.0%
Combustion Turbine	113	36.4	41.3	4,118.8	9.2%
Natural Gas	59	38.7	41.3	2,284.3	5.1%
Oil	0	0.0	0.0	0.0	0.0%
Other	54	34.0	41.2	1,834.5	4.1%
Fuel Cell	0	0.0	0.0	0.0	0.0%
Hydro	1	0.5	113.8	0.5	0.0%
Pumped Storage	1	0.5	113.8	0.5	0.0%
Run of River	0	0.0	0.0	0.0	0.0%
Nuclear	6	888.4	41.6	5,330.5	11.9%
RICE	23	4.4	29.3	99.0	0.2%
Natural Gas	0	0.0	0.0	0.0	0.0%
Oil	11	5.2	46.1	57.1	0.1%
Other	12	3.5	12.5	41.9	0.1%
Solar	0	0.0	0.0	0.0	0.0%
Steam	191	128.5	46.3	34,658.9	77.6%
Coal	162	195.2	52.9	31,621.4	70.8%
Natural Gas	17	115.5	61.7	1,963.5	4.4%
Oil	5	174.4	45.6	872.0	2.0%
Other	7	28.9	25.1	202.0	0.5%
Wind	1	10.4	15.6	10.4	0.0%
Total	339	131.8	46.6	44,684.1	100.0%

Table 12-6 Retirements (MW) by unit type and state: 2011 through 2022

State	Battery	Combined Cycle	CT - Natural Gas	CT - Oil	CT - Other	Fuel Cell	Hydro - Pumped Storage	Hydro - Run of River	Nuclear	RICE - Natural Gas	RICE - Oil	RICE - Other	Solar	Steam - Coal	Steam - Natural Gas	Steam - Oil	Steam - Other	Wind	Total
DC	0.0	0.0	0.0	0.0	240.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	548.0	0.0	0.0	788.0
DE	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	254.0	34.0	0.0	0.0	0.0	288.0
IL	0.0	0.0	296.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	12.5	0.0	1,624.0	0.0	0.0	0.0	0.0	1,932.5
IN	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	982.0	0.0	0.0	0.0	0.0	982.0
KY	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	995.0	0.0	0.0	0.0	0.0	995.0
MD	0.0	0.0	347.5	0.0	105.6	0.0	0.0	0.0	0.0	0.0	0.0	3.8	0.0	635.0	171.0	0.0	0.0	0.0	1,262.9
NC	0.0	0.0	0.0	0.0	31.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	324.5	0.0	0.0	0.0	0.0	355.5
NJ	0.0	158.0	1,590.0	0.0	1,046.6	0.0	0.5	0.0	614.5	0.0	8.0	9.8	0.0	1,543.0	932.5	148.0	10.0	0.0	6,060.9
OH	40.0	0.0	0.0	0.0	286.0	0.0	0.0	0.0	2,134.0	0.0	32.3	0.9	0.0	13,892.6	0.0	0.0	0.0	0.0	16,385.8
PA	1.0	0.0	50.8	0.0	58.0	0.0	0.0	0.0	2,582.0	0.0	13.9	13.0	0.0	4,713.3	283.0	176.0	109.0	10.4	8,010.4
VA	0.0	267.0	0.0	0.0	67.3	0.0	0.0	0.0	0.0	0.0	2.9	2.0	0.0	2,739.0	543.0	0.0	83.0	0.0	3,704.2
WV	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	3,919.0	0.0	0.0	0.0	0.0	3,919.0
Total	41.0	425.0	2,284.3	0.0	1,834.5	0.0	0.5	0.0	5,330.5	0.0	57.1	41.9	0.0	31,621.4	1,963.5	872.0	202.0	10.4	44,684.1

Figure 12-2 is a map of unit retirements between 2011 and 2022, with a mapping to unit names in Table 12-7.

Figure 12-2 Map of PJM unit retirements: 2011 through 2022

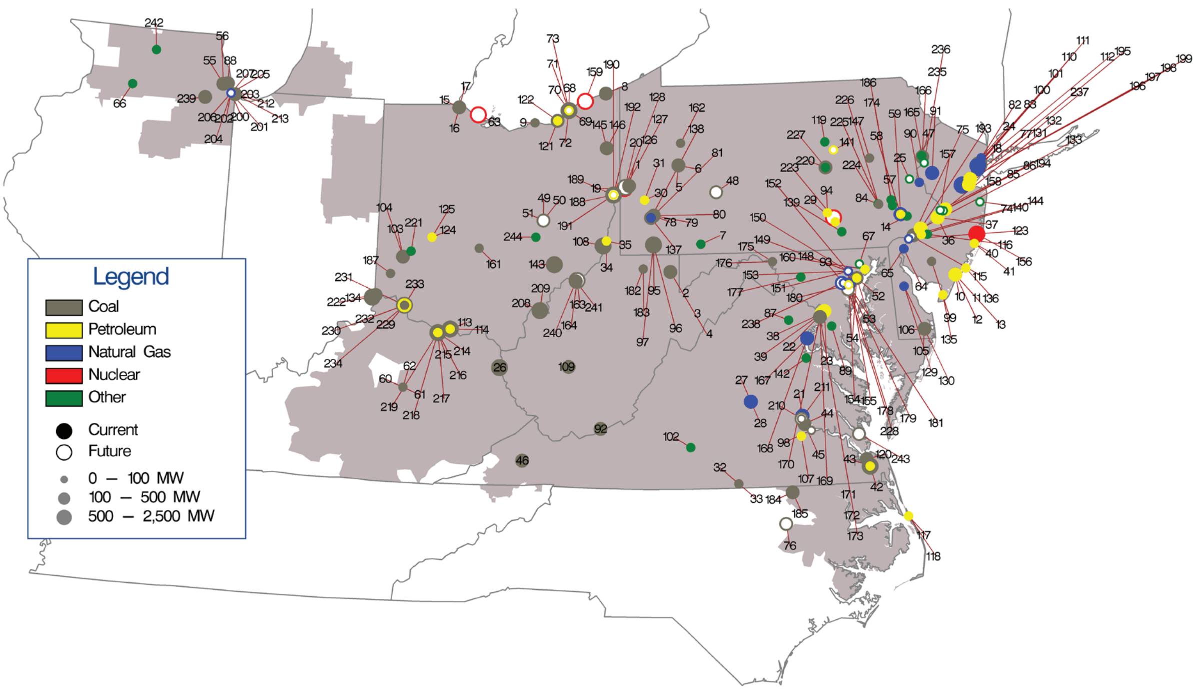


Table 12-7 Unit identification for map of PJM unit retirements: 2011 through 2022

ID	Unit	ID	Unit	ID	Unit	ID	Unit
1	AES Beaver Valley	36	Burlington 8,11	71	Eastlake 4	106	Indian River 3
2	Albright 1	37	Burlington 9	72	Eastlake 5	107	Ingenco Petersburg
3	Albright 2	38	Buzzard Point East Banks 1,2,4-8	73	Eastlake 6	108	Kammer 1-3
4	Albright 3	39	Buzzard Point West Banks 1-9	74	Eddystone 1	109	Kanawha River 1-2
5	Armstrong 1	40	Cedar 1	75	Eddystone 2	110	Kearny 10
6	Armstrong 2	41	Cedar 2	76	Edgecomb NUG (Rocky 1-2)	111	Kearny 11
7	Arnold (Green Mtn. Wind Farm	42	Chesapeake 1-4	77	Edison 1-3	112	Kearny 9
8	Ashtabula 5	43	Chesapeake 7-10	78	Elrama 1	113	Killen 2
9	Avon Lake 7	44	Chesterfield 3	79	Elrama 2	114	Killen CT
10	BL England 1	45	Chesterfield 4	80	Elrama 3	115	Kimberly Clark Generator
11	BL England 2	46	Clinch River 3	81	Elrama 4	116	Kinsley Landfill
12	BL England 3	47	Columbia Dam Hydro	82	Essex 10-11	117	Kitty Hawk GT 1
13	BL England Diesel Units 1-4	48	Colver Power Project	83	Essex 12	118	Kitty Hawk GT 2
14	Barbados AES Battery	49	Conesville 3	84	Evergreen Power United Corstack	119	Koppers Co. IPP
15	Bay Shore 2	50	Conesville 5	85	Fairless Hills Landfill A	120	Lake Kingman
16	Bay Shore 3	51	Conesville 6	86	Fairless Hills Landfill B	121	Lake Shore 18
17	Bay Shore 4	52	Crane 1	87	Fauquier County Landfill	122	Lake Shore EMD
18	Bayonne Cogen Plant (CC)	53	Crane 2	88	Fisk Street 19	123	MH50 Markus Hook Co-gen
19	Beaver Valley U1 Nuclear Generating Unit	54	Crane GT1	89	GUDE Landfill	124	Mad River CTs A
20	Beaver Valley U2 Nuclear Generating Unit	55	Crawford 7	90	Gilbert 1-4	125	Mad River CTs B
21	Bellemeade	56	Crawford 8	91	Glen Gardner 1-8	126	Mansfield 1
22	Benning 15	57	Cromby 1	92	Glen Lyn 5-6	127	Mansfield 2
23	Benning 16	58	Cromby 2	93	Gould Street Generation Station	128	Mansfield 3
24	Bergen 3	59	Cromby D	94	Harrisburg 4 CT	129	McKee 1
25	Bethlehem Renewable Energy Generator (Landfill)	60	Dale 1-2	95	Hatfield's Ferry 1	130	McKee 2
26	Big Sandy 2	61	Dale 3	96	Hatfield's Ferry 2	131	Mercer 1
27	Bremo 3	62	Dale 4	97	Hatfield's Ferry 3	132	Mercer 2
28	Bremo 4	63	Davis Besse U1 Nuclear Generating Unit	98	Hopewell James River Cogeneration	133	Mercer 3
29	Brunner Island Diesels	64	Deepwater 1	99	Howard Down 10	134	Miami Fort 6
30	Brunot Island 1B	65	Deepwater 6	100	Hudson 1	135	Middle 1-3
31	Brunot Island 1C	66	Dixon Lee Landfill Generator	101	Hudson 2	136	Missouri Ave B,C,D
32	Buggs Island 1 (Mecklenberg)	67	Eastern Landfill Gas Generator	102	Hurt NUG	137	Mitchell 2
33	Buggs Island 2 (Mecklenberg)	68	Eastlake 1	103	Hutchings 1-3, 5-6	138	Mitchell 3
34	Burger 3	69	Eastlake 2	104	Hutchings 4	139	Modern Power Landfill NUG
35	Burger EMD	70	Eastlake 3	105	Indian River 1	140	Monmouth NUG landfill

ID	Unit	ID	Unit	ID	Unit
141	Montour ATG	176	R Paul Smith 4	211	Spruance NUG2 (Rich 3-4)
142	Morris Landfill Generator	177	Reichs Ford Road Landfill Generator	212	State Line 3
143	Muskingum River 1-5	178	Riverside 4	213	State Line 4
144	National Park 1	179	Riverside 6	214	Stuart 1
145	Niles 1	180	Riverside 7	215	Stuart 2
146	Niles 2	181	Riverside 8	216	Stuart 3
147	Northeastern Power NEPCO	182	Riversville 5	217	Stuart 4
148	Notch Cliff GT1	183	Riversville 6	218	Stuart Diesels 1-4
149	Notch Cliff GT2	184	Roanoke Valley 1	219	Stuart Diesels 1-4
150	Notch Cliff GT3	185	Roanoke Valley 2	220	Sunbury 1-4
151	Notch Cliff GT4	186	Rolling Hills Landfill Generator	221	Tait Battery
152	Notch Cliff GT5	187	SMART Paper	222	Tanners Creek 1-4
153	Notch Cliff GT6	188	Sammis 1-4	223	Three Mile Island Unit 1
154	Notch Cliff GT7	189	Sammis 5	224	Titus 1
155	Notch Cliff GT8	190	Sammis 6	225	Titus 2
156	Oyster Creek	191	Sammis 7	226	Titus 3
157	Pennsbury Generator Landfill 1	192	Sammis Diesel	227	Viking Energy NUG
158	Pennsbury Generator Landfill 2	193	Schuylkill 1	228	Wagner 2
159	Perry U1 Nuclear Generating Unit	194	Schuylkill Diesel	229	Walter C Beckjord 1
160	Perryman 2	195	Sewaren 1	230	Walter C Beckjord 2
161	Picway 5	196	Sewaren 2	231	Walter C Beckjord 3
162	Piney Creek NUG	197	Sewaren 3	232	Walter C Beckjord 4
163	Pleasants Power Station U1	198	Sewaren 4	233	Walter C Beckjord 5-6
164	Pleasants Power Station U2	199	Sewaren 6	234	Walter C Beckjord GT 1-4
165	Portland 1	200	Southeast Chicago CT11	235	Warren County Landfill
166	Portland 2	201	Southeast Chicago CT12	236	Warren County NUG
167	Possum Point 3	202	Southeast Chicago CT5	237	Werner 1-4
168	Possum Point 4	203	Southeast Chicago CT6	238	Westport 5
169	Potomac River 1	204	Southeast Chicago CT7	239	Will County 3
170	Potomac River 2	205	Southeast Chicago CT8	240	Willow Island 1
171	Potomac River 3	206	Southeast Chicago GT10	241	Willow Island 2
172	Potomac River 4	207	Southeast Chicago GT9	242	Winnebago Landfill
173	Potomac River 5	208	Sporn 1-4	243	Yorktown 1-2
174	Pottstown LF (Moser)	209	Sporn 5	244	Zanesville Landfill
175	R Paul Smith 3	210	Spruance NUG1 (Rich 1-2)		

Current Year Generation Retirements

Table 12-8 shows that in 2018, 5,522.7 MW of generation retired. The largest generator that retired in 2018 was the 614.5 MW Oyster Creek Nuclear Generating Station owned by Exelon Corporation and located in the Jersey Central Power and Light (JCPL) Zone. Of the 5,522.7 MW of generation that retired, 2,364.0 MW (42.8 percent) were located in the DAY Zone.

Table 12-8 Unit deactivations: 2018[24]

Company	Unit Name	ICAP (MW)	Unit Type	Zone Name	Age (Years)	Retirement Date
Biogas Energy Solutions, LLC	Dixon Lee Landfill Generator	4.0	RICE-Other	ComEd	4.8	10-Jan-18
Rockland Capital Energy Investments, LLC	BL England 3	148.0	Steam-Oil	AECO	43.2	24-Jan-18
Riverstone Holdings LLC	Brunner Island Diesels	8.2	RICE-Oil	PPL	50.8	25-Feb-18
Dominion Resources, Inc.	Buggs Island 1 (Mecklenberg)	69.0	Steam-Coal	Dominion	25.5	09-Apr-18
Dominion Resources, Inc.	Buggs Island 2 (Mecklenberg)	69.0	Steam-Coal	Dominion	25.5	09-Apr-18
Dominion Resources, Inc.	Bellemeade	267.0	Combined Cycle	Dominion	21.2	16-Apr-18
Dominion Resources, Inc.	Bremo 3	71.0	Steam-Natural Gas	Dominion	67.9	16-Apr-18
Dominion Resources, Inc.	Bremo 4	156.0	Steam-Natural Gas	Dominion	59.7	16-Apr-18
Evergreen Community Power LLC	Evergreen Power United Corstack	25.0	Steam-Other	Met-Ed	8.7	01-May-18
Biogas Energy Solutions, LLC	Morris Landfill Generator	2.1	RICE-Other	ComEd	5.0	31-May-18
South Jersey Industries, Inc.	Reichs Ford Road Landfill Generator	1.6	CT-Other	APS	8.1	31-May-18
American Electric Power Company, Inc.	Stuart 2	150.0	Steam-Coal	DAY	47.7	01-Jun-18
American Electric Power Company, Inc.	Stuart 3	150.0	Steam-Coal	DAY	46.1	01-Jun-18
American Electric Power Company, Inc.	Stuart 4	150.0	Steam-Coal	DAY	44.0	01-Jun-18
American Electric Power Company, Inc.	Stuart Diesels 1-4	2.4	RICE-Oil	DAY	48.7	01-Jun-18
Avenue Capital Group LLC	Crane 1	190.0	Steam-Coal	BGE	57.0	01-Jun-18
Avenue Capital Group LLC	Crane 2	195.0	Steam-Coal	BGE	55.4	01-Jun-18
Avenue Capital Group LLC	Crane GT1	14.0	CT-Other	BGE	50.9	01-Jun-18
Riverstone Holdings LLC	Bayonne Cogen Plant (CC)	158.0	Combined Cycle	PSEG	29.7	01-Jun-18
The AES Corporation	Killen 2	402.0	Steam-Coal	DAY	36.0	01-Jun-18
The AES Corporation	Killen CT	18.0	CT-Other	DAY	35.2	01-Jun-18
The AES Corporation	Stuart 2	202.0	Steam-Coal	DAY	47.7	01-Jun-18
The AES Corporation	Stuart 3	202.0	Steam-Coal	DAY	46.1	01-Jun-18
The AES Corporation	Stuart 4	202.0	Steam-Coal	DAY	44.0	01-Jun-18
The AES Corporation	Stuart Diesels 1-4	3.0	RICE-Oil	DAY	48.7	01-Jun-18
Vistra Energy Corp	Killen 2	198.0	Steam-Coal	DAY	36.0	01-Jun-18
Vistra Energy Corp	Killen CT	6.0	CT-Other	DAY	35.2	01-Jun-18
Vistra Energy Corp	Stuart 2	225.0	Steam-Coal	DAY	47.7	01-Jun-18
Vistra Energy Corp	Stuart 3	225.0	Steam-Coal	DAY	46.1	01-Jun-18
Vistra Energy Corp	Stuart 4	225.0	Steam-Coal	DAY	44.0	01-Jun-18
Vistra Energy Corp	Stuart Diesels 1-4	3.6	RICE-Oil	DAY	48.7	01-Jun-18
Public Service Enterprise Group Incorporated	Sewaren 1	104.0	Steam-Natural Gas	PSEG	69.6	06-Jun-18
Public Service Enterprise Group Incorporated	Sewaren 2	118.0	Steam-Natural Gas	PSEG	69.6	06-Jun-18
Public Service Enterprise Group Incorporated	Sewaren 3	107.0	Steam-Natural Gas	PSEG	68.7	06-Jun-18
Public Service Enterprise Group Incorporated	Sewaren 4	124.0	Steam-Natural Gas	PSEG	67.0	06-Jun-18
Dominion Resources, Inc.	Hurt NUG	83.0	Steam-Other	Dominion	24.2	24-Jul-18
The AES Corporation	Barbados AES Battery	1.0	Battery	PECO	9.7	29-Jul-18
Quasar Energy Group, LLC	Zanesville Landfill	0.9	RICE-Other	AEP	6.1	08-Sep-18
Exelon Corporation	Oyster Creek Nuclear Generating Station	614.5	Nuclear	JCPL	48.8	17-Sep-18
Vistra Energy Corp	Northeastern Power NEPCO	52.0	Steam-Coal	PPL	26.2	24-Oct-18
Dominion Resources, Inc.	Chesterfield 3	97.5	Steam-Coal	Dominion	66.1	13-Dec-18
Dominion Resources, Inc.	Chesterfield 4	163.0	Steam-Coal	Dominion	58.6	13-Dec-18
Dominion Resources, Inc.	Possum Point 3	96.0	Steam-Natural Gas	Dominion	63.6	13-Dec-18
Dominion Resources, Inc.	Possum Point 4	220.0	Steam-Natural Gas	Dominion	56.7	13-Dec-18
Total		5,522.7				

24 The Killen 2, Killen CT, Stuart 2, 3 and 4 and Stuart Diesels 1-4 units are jointly owned. The MW displayed in each row represents the individual company's share of the retiring unit.

Planned Generation Retirements

Table 12-9 shows that there are 13,398.0 MW of generation that have requested retirement after December 31, 2018, of which 6,791.0 MW (50.7 percent) are located in the ATSI Zone, 7,829.3 MW (58.4 percent) are coal fired steam units and 4,716.0 MW (35.2 percent) are nuclear units. The largest generator pending retirement is the 1,240 MW Perry U1 Nuclear Generating Unit located in the ATSI Zone.

Table 12-9 Planned retirement of PJM units: December 31, 2018

Unit	Zone	ICAP (MW)	Unit Type	Projected Deactivation Date
Spruance NUG1 (aka Spruance 1 Rich 1-2)	Dominion	115.5	Steam-Coal	12-Jan-19
Spruance NUG2 (aka Spruance 2 Rich 3-4)	Dominion	85.0	Steam-Coal	12-Jan-19
Mansfield 1	ATSI	830.0	Steam-Coal	05-Feb-19
Mansfield 2	ATSI	830.0	Steam-Coal	05-Feb-19
Montour ATG	PPL	10.0	Steam-Oil	18-Feb-19
Yorktown 1-2	Dominion	323.0	Steam-Coal	08-Mar-19
Riverside 7	BGE	19.0	CT-Other	14-Mar-19
Hopewell James River Cogeneration	Dominion	89.0	Steam-Coal	31-Mar-19
BL England 2	AECO	155.0	Steam-Coal	30-Apr-19
Monmouth NUG landfill	JCPL	6.4	CT-Other	31-May-19
Conesville 5	AEP	400.0	Steam-Coal	01-Jun-19
Conesville 6	AEP	400.0	Steam-Coal	01-Jun-19
Warren County NUG	JCPL	10.0	Steam-Other	01-Jun-19
MH50 Markus Hook Co-gen	PECO	50.8	CT-Natural Gas	01-Jun-19
Kimberly Clark Generator	PECO	3.3	Steam-Coal	01-Aug-19
Three Mile Island Unit 1 Nuclear Generating Station	Met-Ed	805.0	Nuclear	30-Sep-19
Davis Besse U1 Nuclear Generating Unit	ATSI	894.0	Nuclear	31-May-20
Sammis 1-4	ATSI	640.0	Steam-Coal	31-May-20
Notch Cliff GT1	BGE	14.0	CT-Natural Gas	01-Jun-20
Notch Cliff GT2	BGE	14.0	CT-Natural Gas	01-Jun-20
Notch Cliff GT3	BGE	14.0	CT-Natural Gas	01-Jun-20
Notch Cliff GT4	BGE	14.0	CT-Natural Gas	01-Jun-20
Notch Cliff GT5	BGE	14.6	CT-Natural Gas	01-Jun-20
Notch Cliff GT6	BGE	15.6	CT-Natural Gas	01-Jun-20
Notch Cliff GT7	BGE	14.5	CT-Natural Gas	01-Jun-20
Notch Cliff GT8	BGE	16.0	CT-Natural Gas	01-Jun-20
Westport 5	BGE	115.8	CT-Natural Gas	01-Jun-20
Riverside 8	BGE	20.0	CT-Other	01-Jun-20
Eastern Landfill Gas Generator	BGE	3.0	RICE-Other	01-Jun-20
Wagner 2	BGE	135.0	Steam-Coal	01-Jun-20
Gould Street Generation Station	BGE	97.0	Steam-Natural Gas	01-Jun-20
Southeast Chicago CT5	ComEd	37.0	CT-Natural Gas	01-Jun-20
Southeast Chicago CT6	ComEd	37.0	CT-Natural Gas	01-Jun-20
Southeast Chicago CT7	ComEd	37.0	CT-Natural Gas	01-Jun-20
Southeast Chicago CT8	ComEd	37.0	CT-Natural Gas	01-Jun-20
Southeast Chicago GT9	ComEd	37.0	CT-Natural Gas	01-Jun-20
Southeast Chicago GT10	ComEd	37.0	CT-Natural Gas	01-Jun-20
Southeast Chicago CT11	ComEd	37.0	CT-Natural Gas	01-Jun-20
Southeast Chicago CT12	ComEd	37.0	CT-Natural Gas	01-Jun-20
Pennsbury Generator Landfill 1	PECO	3.0	CT-Other	01-Jun-20
Pennsbury Generator Landfill 2	PECO	3.0	CT-Other	01-Jun-20
Fairless Hills Landfill A	PECO	30.0	Steam-Other	01-Jun-20
Fairless Hills Landfill B	PECO	30.0	Steam-Other	01-Jun-20
Bethlehem Renewable Energy Generator (Landfill)	PPL	5.0	RICE-Other	01-Jun-20
Colver Power Project	PENELEC	110.0	Steam-Coal	01-Sep-20
Edgecomb NUG (aka Edgecomb Rocky 1-2)	Dominion	115.5	Steam-Coal	31-Oct-20
Perry U1 Nuclear Generating Unit	ATSI	1,240.0	Nuclear	31-May-21
Beaver Valley U1 Nuclear Generating Unit	DLCO	892.0	Nuclear	31-May-21
Eastlake 6	ATSI	24.0	CT-Other	01-Jun-21
Sammis Diesel	ATSI	13.0	RICE-Oil	01-Jun-21
Mansfield 3	ATSI	830.0	Steam-Coal	01-Jun-21
Beaver Valley U2 Nuclear Generating Unit	DLCO	885.0	Nuclear	31-Oct-21
Pleasants Power Station U1	APS	639.0	Steam-Coal	01-Jun-22
Pleasants Power Station U2	APS	639.0	Steam-Coal	01-Jun-22
Sammis 5	ATSI	290.0	Steam-Coal	01-Jun-22
Sammis 6	ATSI	600.0	Steam-Coal	01-Jun-22
Sammis 7	ATSI	600.0	Steam-Coal	01-Jun-22
Total		13,398.0		

Generation Queue

Any entity that requests interconnection of a new generating facility, including increases to the capacity of an existing generating unit, or that requests interconnection of a merchant transmission facility, must follow the process defined in the PJM tariff to obtain interconnection service.[25] PJM's process is designed to ensure that new generation is added in a reliable and systematic manner. The process is complex and time consuming at least in part as a result of the required analyses. The cost, time and uncertainty associated with interconnecting to the grid may create barriers to entry for potential entrants. The MMU recommends that barriers to entry be addressed in a timely manner in order to help ensure that the market will result in the entry of new capacity to meet the needs of PJM market participants.

Generation request queues are groups of proposed projects, including new units, reratings of existing units, capacity resources and energy only resources. Each queue is open for a fixed amount of time. Studies commence on all projects in a given queue when that queue closes. Queues A and B were open for a year. Queues C through T were open for six months. Starting in February 2008, Queues U through Y1 were open for three months. In May 2012, the duration of the queue period was reset to six months, starting with Queue Y2. Queue AD2 began on October 1, 2017 and closed on March 31, 2018. Queue AE1 began on April 1, 2018 and closed on September 30, 2018. Queue AF1 began on October 1, 2018 and will close on March 31, 2019.

Projects that do not meet submission requirements are removed from the queue. All projects that have entered a queue and have met the submission requirements have a status assigned. Projects listed as active are undergoing one of the studies (feasibility, system impact, facility) required to proceed. Other status options are under construction, suspended, and in service. A project cannot be suspended until it has reached the status of under construction. Any project that entered the queue before February 1, 2011, can be suspended for up to three years. Projects that entered the queue after February 1, 2011, face an additional restriction in that the suspension period is reduced to one year if they affect any project later in the queue.[26] When a project is suspended, PJM extends the scheduled milestones by the duration of the suspension. If, at any time, a milestone is not met, PJM will initiate the termination of the Interconnection Service Agreement (ISA) and the corresponding cancellation costs must be paid by the customer.[27]

The PJM queue evaluation process has been substantially improved in recent years and it is more efficient and effective as a result.[28] The PJM queue evaluation process should continue to be improved to help ensure that barriers to competition from new generation investments are not created. The 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.

Process Timelines

In the study phase of the interconnection planning process, a series of studies are performed to determine the feasibility, impact, and cost of projects in the queue. Table 12-10 is an overview of PJM's study process. System impact and facilities studies are often redone when a project is withdrawn in order to determine the impact on the projects remaining in the queue.

In 2016, the PJM Earlier Queue Submitted Task Force stakeholder group made changes to the interconnection process to address some of the issues related to delays observed in the various stages of the study phase. The changes became effective with the AC2 Queue that closed on March 31, 2017. Until there has been additional time and queue processing to validate the effectiveness of these changes, 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.

25 See OATT Parts IV & VI.

26 See "PJM Manual 14C: Generation and Transmission Interconnection Process," Rev. 13 (Aug.23, 2018).

27 PJM does not track the duration of suspensions or PJM termination of projects.

28 See *PJM Interconnection, L.L.C.*, Docket No. ER12-1177 (Feb. 29, 2012).

Table 12-10 PJM generation planning process

Process Step	Start on	Financial Obligation	Days for PJM to Complete	Days for Applicant to Decide Whether to Continue
Feasibility Study	Close of current queue	Cost of study (partially refundable deposit)	90	30
System Impact Study	Upon acceptance of the System Impact Study Agreement	Cost of study (partially refundable deposit)	120	30
Facilities Study	Upon acceptance of the Facilities Study Agreement	Cost of study (refundable deposit)	Varies	60
Schedule of Work	Upon acceptance of Interconnection Service Agreement (ISA)	Letter of credit for upgrade costs	Varies	37
Construction (only for new generation)	Upon acceptance of Interconnection Construction Service Agreement (ICSA)	None	Varies	NA

Planned Generation Additions

Expected net revenues provide incentives to build new generation to serve PJM markets. The amount of planned new generation in PJM reflects investors' perception of the incentives provided by the combination of revenues from the PJM energy, capacity and ancillary service markets. On December 31, 2018, 114,953.7 MW of capacity were in generation request queues for construction through 2029. Although it is clear that not all generation in the queues will be built, PJM has added capacity steadily since markets were implemented on April 1, 1999.[29]

Table 12-11 shows MW in queues by expected completion year and MW changes in the queue between December 31, 2017, and December 31, 2018, for ongoing projects, i.e. projects with the status active, under construction or suspended.[30] Projects that are already in service are not included here. Projects that have been withdrawn or removed from the queue are no longer included in the totals. The total MW in queues increased by 41,846.2 MW (57.2 percent) from 73,107.6 MW at the end of 2017 to 114,953.7 MW on December 31, 2018.

Table 12-11 Queue comparison by expected completion year (MW): December 31, 2017 and December 31, 2018[31]

			Year Change	
Year	As of 12/31/2017	As of 12/31/2018	MW	Percent
2008	12.0	12.0	0.0	0.0%
2009	0.0	0.0	0.0	0.0%
2010	0.0	0.0	0.0	0.0%
2011	102.5	102.5	0.0	0.0%
2012	91.2	91.2	0.0	0.0%
2013	210.5	210.5	0.0	0.0%
2014	25.0	10.0	(15.0)	(60.0%)
2015	439.9	234.1	(205.8)	(46.8%)
2016	1,879.5	725.3	(1,154.2)	(61.4%)
2017	3,975.9	2,273.5	(1,702.4)	(42.8%)
2018	12,088.2	8,218.9	(3,869.3)	(32.0%)
2019	21,910.1	24,348.3	2,438.3	11.1%
2020	22,811.9	28,623.8	5,811.8	25.5%
2021	7,100.0	26,125.7	19,025.7	268.0%
2022	2,460.9	13,756.1	11,295.2	459.0%
2023	0.0	5,715.5	5,715.5	0.0%
2024	0.0	2,106.0	2,106.0	0.0%
2025	0.0	800.1	800.1	0.0%
2026	0.0	0.0	0.0	0.0%
2027	0.0	800.1	800.1	0.0%
2028	0.0	0.0	0.0	0.0%
2029	0.0	800.1	800.1	0.0%
Total	73,107.6	114,953.7	41,846.2	57.2%

Table 12-12 shows the project status changes in more detail and how scheduled queue capacity has changed between December 31, 2017, and December 31, 2018. For example, 55,177.6 MW entered the queue in 2018. Of those 55,177.6 MW, 13,331.5 MW have been withdrawn. Of the total 71,354.4 MW marked as active on December 31, 2017, 14,480.9 MW were withdrawn, 2,214.2 MW were suspended, 868.8 MW started construction, and 514.1 MW went into service by December 31, 2018. Analysis of projects that were suspended on December

29 See Monitoring Analytics, "New Generation in the PJM Capacity Market: MW and Funding Sources for Delivery Years 2007/2008 through 2018/2019," <http://www.monitoringanalytics.com/reports/Reports/2016/New_Generation_in_the_PJM_Capacity_Market_20160504.pdf>.

30 Expected completion dates are entered when the project enters the queue. Actual completion dates are generally different than expected completion dates.

31 Wind and solar capacity in Table 12-11 through Table 12-15 have not been adjusted to reflect derating.

31, 2017 show that 3,800.5 MW came out of suspension and are now active and 20.0 MW began construction in 2018.

Table 12-12 Change in project status (MW): December 31, 2017 to December 31, 2018

		Status at 12/31/2018				
Status as 12/31/2017	Total at 12/31/2017	Active	In Service	Under Construction	Suspended	Withdrawn
(Entered during 2018)	0.0	41,846.2	0.0	0.0	0.0	13,331.5
Active	71,354.4	53,276.4	514.1	868.8	2,214.2	14,480.9
In Service	51,676.6	0.0	51,674.7	0.0	0.0	1.9
Under Construction	18,753.2	0.0	8,819.1	9,052.6	594.6	286.9
Suspended	9,356.1	3,800.5	120.0	20.0	3,280.5	2,135.1
Withdrawn	322,847.7	0.0	0.0	0.0	0.0	322,847.7
Total	473,987.9	98,923.1	61,128.0	9,941.4	6,089.3	353,083.9

On December 31, 2018, 114,953.7 MW of capacity were in generation request queues in the status of active, suspended or under construction. Table 12-13 shows each status by unit type. Of the 98,923.1 MW in the status of Active on December 31, 2018, 36,176.1 MW (36.6 percent) were combined cycle projects. Of the 9,941.4 MW in the status of under construction, 6,810.6 MW (68.5 percent) were combined cycle projects.

Table 12-13 Current project status (MW) by unit type: December 31, 2018

	Battery	Combined Cycle	CT - Natural Gas	CT - Oil	CT - Other	Fuel Cell	Hydro - Pumped Storage	Hydro - Run of River	Nuclear	RICE - Natural Gas	RICE - Oil	RICE - Other	Solar	Steam - Coal	Steam - Natural Gas	Steam - Oil	Steam - Other	Wind	Total
Active	1,063.3	36,176.1	5,151.9	14.0	0.0	0.0	1,034.0	20.5	167.5	91.9	4.0	6.8	32,699.0	99.0	94.0	0.0	40.0	22,261.1	98,923.1
Suspended	86.3	3,857.1	268.8	0.0	0.0	0.0	0.0	0.0	0.0	79.6	0.0	0.0	424.9	0.0	0.0	0.0	16.0	1,356.6	6,089.3
Under Construction	46.1	6,810.6	253.0	0.0	3.2	0.0	0.0	22.7	0.0	21.2	0.0	0.0	357.8	48.0	0.0	0.0	62.5	2,316.3	9,941.4
Total	1,195.6	46,843.8	5,673.7	14.0	3.2	0.0	1,034.0	43.2	167.5	192.7	4.0	6.8	33,481.7	147.0	94.0	0.0	118.5	25,934.0	114,953.7

A significant shift in the distribution of unit types within the PJM footprint continues to develop as natural gas fired units enter the queue and coal fired steam units retire. As of December 31, 2018, there were 52,804.2 MW of natural gas fired capacity active, suspended or under construction in PJM queues (including combined cycle units, CTs, RICE units, and natural gas fired steam units). As of December 31, 2018, there were only 147.0 MW of coal fired steam capacity active, suspended or under construction in PJM queues.

There are 7,829.3 MW of coal fired steam capacity and 676.3 MW of natural gas capacity slated for deactivation between December 31, 2018, and December 31, 2022 (See Table 12-9). The replacement of coal fired steam units by natural gas units will significantly affect future congestion, the role of firm and interruptible gas supply, and natural gas supply infrastructure.

Table 12-14 shows the amount of capacity active, in service, under construction, suspended, or withdrawn for each queue since the beginning of the RTEP process and the total amount of capacity that had been included in each queue. All items in queues A-M are either in service or have been withdrawn. As of December 31, 2018, there are 114,953.7 MW of capacity in queues that are not yet in service or withdrawn, of which 5.3 percent are suspended, 8.6 percent are under construction and 86.1 percent have not begun construction.

Table 12-14 Capacity in PJM queues (MW): December 31, 2018[32]

Queue	Active	In Service	Under Construction	Suspended	Withdrawn	Total
A Expired 31-Jan-98	0.0	9,094.0	0.0	0.0	17,252.0	26,346.0
B Expired 31-Jan-99	0.0	4,645.5	0.0	0.0	14,956.7	19,602.2
C Expired 31-Jul-99	0.0	531.0	0.0	0.0	3,558.3	4,089.3
D Expired 31-Jan-00	0.0	850.6	0.0	0.0	7,358.0	8,208.6
E Expired 31-Jul-00	0.0	795.2	0.0	0.0	8,021.8	8,817.0
F Expired 31-Jan-01	0.0	52.0	0.0	0.0	3,092.5	3,144.5
G Expired 31-Jul-01	0.0	1,189.6	0.0	0.0	17,961.8	19,151.4
H Expired 31-Jan-02	0.0	702.5	0.0	0.0	8,421.9	9,124.4
I Expired 31-Jul-02	0.0	103.0	0.0	0.0	3,728.4	3,831.4
J Expired 31-Jan-03	0.0	42.0	0.0	0.0	846.0	888.0
K Expired 31-Jul-03	0.0	93.1	0.0	0.0	485.3	578.4
L Expired 31-Jan-04	0.0	256.5	0.0	0.0	4,033.7	4,290.2
M Expired 31-Jul-04	0.0	504.8	0.0	0.0	3,705.6	4,210.4
N Expired 31-Jan-05	0.0	2,398.8	38.0	0.0	8,090.2	10,527.0
O Expired 31-Jul-05	0.0	1,665.2	225.0	0.0	5,466.8	7,357.0
P Expired 31-Jan-06	0.0	3,037.3	253.0	0.0	5,320.5	8,610.8
Q Expired 31-Jul-06	0.0	3,147.9	0.0	0.0	11,385.7	14,533.6
R Expired 31-Jan-07	600.0	1,986.4	0.0	440.0	19,668.9	22,695.3
S Expired 31-Jul-07	70.0	3,543.5	0.0	0.0	12,396.5	16,010.0
T Expired 31-Jan-08	0.0	3,116.5	1,080.0	0.0	23,313.3	27,509.8
U1 Expired 30-Apr-08	0.0	206.9	12.0	0.0	7,937.8	8,156.7
U2 Expired 31-Jul-08	420.0	267.5	260.0	300.0	15,932.2	17,179.7
U3 Expired 31-Oct-08	100.0	333.0	20.0	0.0	2,515.6	2,968.6
U4 Expired 31-Jan-09	500.0	85.2	0.0	0.0	4,445.0	5,030.2
V1 Expired 30-Apr-09	40.0	197.9	0.0	0.0	2,532.8	2,770.7
V2 Expired 31-Jul-09	0.0	989.9	16.1	150.0	3,475.1	4,631.1
V3 Expired 31-Oct-09	200.0	912.0	0.0	20.0	3,822.7	4,954.7
V4 Expired 31-Jan-10	0.0	748.8	0.0	205.0	3,503.0	4,456.8
W1 Expired 30-Apr-10	13.5	345.9	300.0	0.0	5,139.5	5,798.9
W2 Expired 31-Jul-10	10.0	351.7	0.0	23.0	3,018.7	3,403.4
W3 Expired 31-Oct-10	371.0	490.3	57.7	100.0	8,203.1	9,222.0
W4 Expired 31-Jan-11	5.0	1,101.8	399.9	0.0	4,115.6	5,622.3
X1 Expired 30-Apr-11	0.0	1,103.8	0.0	0.0	6,200.6	7,304.4
X2 Expired 31-Jul-11	0.0	3,544.4	187.5	585.0	5,578.4	9,895.2
X3 Expired 31-Oct-11	0.0	89.2	20.0	894.0	6,771.9	7,775.1
X4 Expired 31-Jan-12	0.0	2,929.4	19.5	0.0	2,419.4	5,368.3
Y1 Expired 30-Apr-12	34.0	1,797.5	452.0	72.0	5,721.7	8,077.2
Y2 Expired 31-Oct-12	378.3	1,051.8	387.1	229.0	9,247.5	11,293.7
Y3 Expired 30-Apr-13	0.0	626.3	1,004.2	0.0	4,609.2	6,239.6
Z1 Expired 31-Oct-13	713.0	1,247.0	2,127.8	39.8	3,997.2	8,124.8
Z2 Expired 30-Apr-14	220.6	2,272.4	585.0	72.9	2,949.9	6,100.8
AA1 Expired 31-Oct-14	3,113.0	1,009.7	1,363.0	601.1	5,911.9	11,998.7
AA2 Expired 30-Apr-15	5,011.2	496.9	614.7	790.0	9,153.5	16,066.3
AB1 Expired 31-Oct-15	9,397.0	846.5	243.8	221.3	9,744.0	20,452.6
AB2 Expired 31-Mar-16	8,974.7	122.5	55.0	118.6	5,946.6	15,217.4
AC1 Expired 30-Sep-16	11,990.3	103.2	219.5	1,203.7	6,558.9	20,075.6
AC2 Expired 30-Apr-17	5,186.6	80.0	0.6	23.9	7,330.6	12,621.6
AD1 Expired 30-Sep-17	9,085.0	21.2	0.0	0.0	2,354.9	11,461.1
AD2 Expired 31-Mar-18	12,589.6	0.0	0.0	0.0	7,880.9	20,470.5
AE1 Expired 30-Sep-18	26,683.9	0.0	0.0	0.0	6,942.0	33,625.9
AE2 Through 31-Mar-19	3,216.3	0.0	0.0	0.0	60.0	3,276.3
Total	98,923.1	61,128.0	9,941.4	6,089.3	353,083.9	529,165.5

Table 12-15 shows the projects with a status of active, suspended or under construction, by unit type, and control zone. As of December 31, 2018, 114,953.7 MW of capacity were in generation request queues for construction through 2029.[33] Table 12-15 also shows the planned retirements for each zone.

32 Projects listed as partially in service are counted as in service for the purposes of this analysis.

33 Since wind resources cannot be dispatched on demand, PJM rules previously required that the unforced capacity of wind resources be derated to 20 percent of nameplate capacity until actual generation data are available. Beginning with Queue U, PJM derated wind resources to 13 percent of nameplate capacity until there is operational data to support a different conclusion. PJM derated solar resources to 38 percent of nameplate capacity. Effective June 1, 2017, PJM adjusted the derates of wind and solar resources. The capacity factor derates for wind resources are dependent on the wind farm locations and have an average derate of 16.2 percent. The capacity factor derates for solar resources are dependent on the solar installation type and have an average derate of 46.7 percent. Based on the derating of 25,934.0 MW of wind resources and 33,481.7 MW of solar resources, using the average derate factors, the 114,953.7 MW currently under construction, suspended or active in the queue would be reduced to 74,545.4 MW.

Table 12-15 Queue totals for projects (active, suspended and under construction) by LDA, control zone and unit type (MW): December 31, 2018[34]

LDA	Zone	Battery	CC	CT - Natural Gas	CT - Oil	CT - Other	Fuel Cell	Hydro - Pumped Storage	Hydro - Run of River	Nuclear	RICE - Natural Gas	RICE - Oil	RICE - Other	Solar	Steam - Coal	Steam - Natural Gas	Steam - Oil	Steam - Other	Wind	Total Queue Capacity	Planned Retirments
EMAAC	AECO	100.0	1,448.6	388.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	311.5	0.0	0.0	0.0	0.0	521.0	2,769.1	155.0
	DPL	21.0	451.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	6.0	1,442.2	0.0	0.0	0.0	0.0	599.8	2,520.0	0.0
	JCPL	154.9	1,175.0	200.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	177.7	0.0	0.0	0.0	0.0	3,016.0	4,723.5	16.4
	PECO	0.0	982.0	29.0	0.0	0.0	0.0	0.0	0.0	94.0	0.0	4.0	0.0	18.0	0.0	0.0	0.0	0.0	0.0	1,127.0	120.1
	PSEG	2.0	3,710.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	92.3	0.0	0.0	0.0	0.0	0.0	3,804.8	0.0
	RECO	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	60.0	0.0	0.0	0.0	0.0	0.0	60.0	0.0
	EMAAC Total	277.8	7,767.1	617.0	0.0	0.0	0.0	0.0	0.0	94.0	0.0	4.0	6.0	2,101.6	0.0	0.0	0.0	0.0	4,136.8	15,004.3	291.5
SWMAAC	BGE	0.1	0.0	153.6	14.0	0.0	0.0	0.0	0.0	45.5	1.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	214.5	506.5
	Pepco	0.0	1,197.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	176.5	0.0	0.0	0.0	0.0	0.0	1,373.6	0.0
	SWMAAC Total	0.1	1,197.1	153.6	14.0	0.0	0.0	0.0	0.0	45.5	1.3	0.0	0.0	176.5	0.0	0.0	0.0	0.0	0.0	1,588.1	506.5
WMAAC	Met-Ed	0.0	598.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	544.6	0.0	0.0	0.0	0.0	0.0	1,143.5	805.0
	PENELEC	0.0	1,348.0	549.8	0.0	0.0	0.0	0.0	0.0	0.0	119.6	0.0	0.0	458.8	0.0	0.0	0.0	0.0	290.3	2,766.5	110.0
	PPL	238.8	2,205.8	0.0	0.0	0.0	0.0	1,000.0	0.0	0.0	0.0	0.0	0.0	174.6	0.0	0.0	0.0	16.0	355.3	3,990.5	15.0
	WMAAC Total	238.8	4,152.7	549.8	0.0	0.0	0.0	1,000.0	0.0	0.0	119.6	0.0	0.0	1,178.0	0.0	0.0	0.0	16.0	645.6	7,900.5	930.0
Non-MAAC	AEP	226.0	8,016.0	1,491.0	0.0	3.2	0.0	34.0	0.0	28.0	12.0	0.0	0.8	7,776.9	101.0	30.0	0.0	40.0	6,689.3	24,448.2	800.0
	APS	145.5	7,595.7	120.0	0.0	0.0	0.0	0.0	15.0	0.0	59.8	0.0	0.0	1,360.7	0.0	0.0	0.0	0.0	1,102.4	10,399.1	1,278.0
	ATSI	8.8	5,805.0	70.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	999.1	0.0	0.0	0.0	0.0	816.1	7,698.9	6,791.0
	ComEd	158.9	6,709.2	1,238.0	0.0	0.0	0.0	0.0	22.7	0.0	0.0	0.0	0.0	2,618.5	0.0	64.0	0.0	0.0	9,322.7	20,134.0	296.0
	DAY	19.9	1,150.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1,136.5	12.0	0.0	0.0	0.0	100.0	2,418.4	0.0
	DEOK	19.8	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	380.0	20.0	0.0	0.0	0.0	0.0	419.8	0.0
	DLCO	20.0	0.0	205.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	20.0	0.0	0.0	0.0	0.0	0.0	245.0	1,777.0
	Dominion	80.0	4,451.0	1,156.3	0.0	0.0	0.0	0.0	5.5	0.0	0.0	0.0	0.0	14,748.0	14.0	0.0	0.0	62.5	3,121.2	23,638.5	728.0
	EKPC	0.0	0.0	73.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	986.0	0.0	0.0	0.0	0.0	0.0	1,059.0	0.0
	OVEC	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	RMU	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Non-MAAC Total	678.9	33,726.9	4,353.3	0.0	3.2	0.0	34.0	43.2	28.0	71.8	0.0	0.8	30,025.7	147.0	94.0	0.0	102.5	21,151.6	90,460.8	11,670.0
	Total	1,195.6	46,843.8	5,673.7	14.0	3.2	0.0	1,034.0	43.2	167.5	192.7	4.0	6.8	33,481.7	147.0	94.0	0.0	118.5	25,934.0	114,953.7	13,398.0

Withdrawn Projects

The queue contains a substantial number of projects that are not likely to be built. The queue process results in a substantial number of projects that are withdrawn. Manual 14B requires PJM to apply a commercial probability factor at the feasibility study stage to improve the accuracy of capacity and cost estimates. The commercial probability factor is based on the historical incidence of projects dropping out of the queue at the impact study stage, but the actual calculation of commercial probability factors is less than transparent.[35] The impact and facilities studies are performed using the full amount of planned generation in the queues. The actual withdrawal rates are shown in Table 12-16 and Table 12-17.

Table 12-16 shows the milestone status when projects were withdrawn, for all withdrawn projects. Of the 2,392 projects withdrawn, 1,164 (48.7 percent) were withdrawn before the system impact study was completed. Once a Construction Service Agreement (CSA) is executed, the financial obligation for any necessary transmission upgrades cannot be retracted. Of the 2,392 projects withdrawn, 463 (19.4 percent) were withdrawn after the completion of a Construction Service Agreement.

Table 12-16 Last milestone at time of withdrawal: January 1997 through December 2018

Milestone Completed	Projects Withdrawn	Percent	Average Days	Maximum Days
Never Started	397	16.6%	95	875
Feasibility Study	767	32.1%	274	1,633
System Impact Study	485	20.3%	752	3,248
Facilities Study	280	11.7%	1,072	3,454
Construction Service Agreement (CSA) or beyond	463	19.4%	1,266	4,249
Total	2,392	100.0%		

34 This data includes only projects with a status of active, under construction, or suspended.
35 See PJM, "Manual 14B: PJM Region Transmission Planning Process," Rev. 42 (Aug. 23, 2018).

Average Time in Queue

Table 12-17 shows the time spent at various stages in the queue process and the completion time for the studies performed. For completed projects, there is an average time of 1,017 days, or 2.8 years, between entering a queue and going into service. For withdrawn projects, there is an average time of 617 days, or 1.7 years, between entering a queue and withdrawing.

Table 12-17 Project queue times by status (days): December 31, 2018[36]

Status	Average (Days)	Standard Deviation	Minimum	Maximum
Active	501	609	0	4,211
In-Service	1,017	728	0	4,024
Suspended	1,500	905	366	4,177
Under Construction	1,820	1,073	486	4,933
Withdrawn	617	689	0	4,249

Table 12-18 presents information on the time in the stages of the queue for those projects not yet in service or already withdrawn. Of the 936 projects in the queue as of December 31, 2018, 214 (22.9 percent) had a completed feasibility study and 205 (21.9 percent) were under construction.

Table 12-18 Project queue times by milestone (days): December 31, 2018

Milestone Reached	Number of Projects	Percent of Total Projects	Average Days	Maximum Days
Under Review	244	26.1%	142	460
Feasibility Study	214	22.9%	481	1,439
System Impact Study	162	17.3%	868	3,662
Facilities Study	43	4.6%	1,188	3,746
Construction Service Agreement (CSA) or beyond	273	29.2%	1,592	5,208
Total	936	100.0%		

Completion Rates

The probability of a project going into service increases as each step of the planning process is completed. Table 12-19 shows the historic completion rates (MW energy) by unit type for projects that have completed the system impact study, facilities study and construction service agreement stages. For example, of all wind projects to ever enter the queue and complete the system impact study stage, 16.0 percent of the queued MW have gone into service. The completion rate for wind projects increases to 31.0 percent when wind projects complete the facility study agreement, and further increases to 48.0 percent when wind projects complete the construction service agreement.

Table 12-19 Historic completion rates (MW energy) by unit type for projects with a completed SIS, FSA and CSA: January 1997 through December 2018

Unit Type	Completion Rate (SIS)	Completion Rate (FSA)	Completion Rate (CSA)
Battery	22.5%	45.0%	53.5%
CC	29.7%	49.4%	83.5%
CT - Natural Gas	82.0%	85.0%	89.6%
CT - Oil	35.6%	60.2%	90.8%
CT - Other	12.3%	18.7%	29.6%
Fuel Cell	0.0%	0.0%	0.0%
Hydro - Pumped Storage	100.0%	100.0%	100.0%
Hydro - Run of River	40.0%	55.7%	61.1%
Nuclear	34.8%	41.7%	51.1%
RICE - Natural Gas	34.7%	50.5%	59.1%
RICE - Oil	30.6%	55.9%	55.9%
RICE - Other	90.0%	91.7%	92.5%
Solar	15.0%	28.1%	35.8%
Steam - Coal	12.9%	24.2%	35.9%
Steam - Natural Gas	90.1%	90.1%	90.1%
Steam - Oil	0.0%	0.0%	0.0%
Steam - Other	27.9%	37.2%	45.2%
Wind	16.0%	31.0%	48.0%

Queue Analysis by Fuel Group

The time it takes to complete a study depends on the backlog and the number of projects in the queue, but not on the size of the project. Table 12-20 shows the number of projects that entered the queue by year and by fuel group. The fuel groups are nuclear units, renewable units (including solar, hydro, storage, biomass and wind) and traditional units (all other fuels). The number of queue entries has increased during the past several years, primarily by renewable projects. Of the 1,492 projects entered in 2015, 2016, 2017 and 2018, 1,196 projects, 80.2 percent, were renewable. Of the 429 projects entered in 2018, 380 projects, 88.6 percent, were renewable.

36 The queue data shows that some projects were withdrawn and a withdrawal date was not identified. These projects were removed for the purposes of this analysis.

Table 12-20 Number of projects entered in the queue: December 31, 2018

	Fuel Group			
Year Entered	Nuclear	Renewable	Traditional	Total
1997	2	0	11	13
1998	0	0	18	18
1999	1	5	84	90
2000	2	3	78	83
2001	4	6	81	91
2002	3	15	33	51
2003	1	34	18	53
2004	4	17	33	54
2005	3	75	55	133
2006	9	67	81	157
2007	9	65	145	219
2008	3	109	104	216
2009	10	109	54	173
2010	5	375	61	441
2011	6	268	81	355
2012	2	70	87	159
2013	1	75	78	154
2014	0	121	71	192
2015	0	196	113	309
2016	2	320	77	399
2017	2	300	53	355
2018	1	380	48	429
Total	70	2,610	1,464	4,144

Renewable projects comprise the majority of projects entered in the queue, as well as what is currently active in the queue. Renewable projects make up 53.7 percent of the nameplate MW currently active, suspended or under construction in the queue (Table 12-21).

Table 12-21 Queue details by fuel group: December 31, 2018

Fuel Group	Number of Projects	Percent of Projects	MW	Percent MW
Nuclear	9	1.0%	167.5	0.1%
Renewable	734	78.4%	61,688.6	53.7%
Traditional	193	20.6%	53,097.7	46.2%
Total	936	100.0%	114,953.7	100.0%

Queue Analysis by Unit Type and Project Classification

Table 12-22 shows the current status of all generation queue projects by unit type and project classification from January 1, 1997, through December 31, 2018. As of December 31, 2018, 4,144 projects, representing 529,165.5 MW, have entered the queue process since its inception. Of those, 816 projects, representing 61,128.0 MW, went into service. Of the projects that entered the queue process, 2,392 projects, representing 353,083.9 MW (66.7 percent of the MW) withdrew prior to completion. Such projects may create barriers to entry for projects that would otherwise be completed by taking up queue positions, increasing interconnection costs and creating uncertainty.

A total of 3,375 projects have been classified as new generation and 769 projects have been classified as upgrades. Wind, solar and natural gas projects have accounted for 3,290 projects, or 79.4 percent, of all 4,144 generation queue projects.

Table 12-22 Status of all generation queue projects: January 1997 through December 2018

		Number of Projects																		
Project Status	Project Classification	Battery	CC	CT - Natural Gas	CT - Oil	CT - Other	Fuel Cell	Hydro - Pumped Storage	Hydro - Run of River	Nuclear	RICE - Natural Gas	RICE - Oil	RICE - Other	Solar	Steam - Coal	Steam - Natural Gas	Steam - Oil	Steam - Other	Wind	Total
In Service	New Generation	19	54	48	10	24	3	0	11	2	8	0	55	130	8	5	0	3	78	458
	Upgrade	4	75	90	15	5	0	2	16	41	8	1	14	16	51	7	0	7	6	358
Under Construction	New Generation	23	8	1	0	1	0	0	2	0	2	0	0	19	0	0	0	0	12	68
	Upgrade	1	13	2	0	0	0	0	0	0	0	0	1	3	2	0	0	1	3	26
Suspended	New Generation	7	5	3	0	0	0	0	0	0	4	0	0	32	0	0	0	1	10	62
	Upgrade	3	5	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1	10
Withdrawn	New Generation	101	406	16	9	81	27	1	39	9	20	12	15	951	55	1	0	34	404	2,181
	Upgrade	14	83	5	13	13	2	0	4	9	0	2	2	28	14	0	0	2	20	211
Active	New Generation	27	39	14	1	0	0	2	1	1	5	0	1	438	0	0	0	0	77	606
	Upgrade	10	41	29	0	0	0	1	2	8	1	1	2	40	5	3	0	1	20	164
Total Projects	New Generation	177	512	82	20	106	30	3	53	12	39	12	71	1,570	63	6	0	38	581	3,375
	Upgrade	32	217	127	28	18	2	3	22	58	9	4	19	87	72	10	0	11	50	769

Table 12-23 shows the totals in Table 12-22 by share of classification as new generation or upgrade. Within a unit type the shares of upgrades add to 100 percent and the shares of new generation add to 100 percent. For example, 72.7 percent of all hydro run of river projects classified as upgrades are currently in service in PJM, 18.2 percent of hydro run of river upgrades were withdrawn and 9.1 percent of hydro run of river upgrades are active in the queue.

Table 12-23 Status of all generation queue projects as a percent of total projects by classification: January 1997 through December 2018

		Percent of Projects																		
Project Status	Project Classification	Battery	CC	CT - Natural Gas	CT - Oil	CT - Other	Fuel Cell	Hydro - Pumped Storage	Hydro - Run of River	Nuclear	RICE - Natural Gas	RICE - Oil	RICE - Other	Solar	Steam - Coal	Steam - Natural Gas	Steam - Oil	Steam - Other	Wind	Total
In Service	New Generation	10.7%	10.5%	58.5%	50.0%	22.6%	10.0%	0.0%	20.8%	16.7%	20.5%	0.0%	77.5%	8.3%	12.7%	83.3%	0.0%	7.9%	13.4%	13.6%
	Upgrade	12.5%	34.6%	70.9%	53.6%	27.8%	0.0%	66.7%	72.7%	70.7%	88.9%	25.0%	73.7%	18.4%	70.8%	70.0%	0.0%	63.6%	12.0%	46.6%
Under Construction	New Generation	13.0%	1.6%	1.2%	0.0%	0.9%	0.0%	0.0%	3.8%	0.0%	5.1%	0.0%	0.0%	1.2%	0.0%	0.0%	0.0%	0.0%	2.1%	2.0%
	Upgrade	3.1%	6.0%	1.6%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	5.3%	3.4%	2.8%	0.0%	0.0%	9.1%	6.0%	3.4%
Suspended	New Generation	4.0%	1.0%	3.7%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	10.3%	0.0%	0.0%	2.0%	0.0%	0.0%	0.0%	2.6%	1.7%	1.8%
	Upgrade	9.4%	2.3%	0.8%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	2.0%	1.3%
Withdrawn	New Generation	57.1%	79.3%	19.5%	45.0%	76.4%	90.0%	33.3%	73.6%	75.0%	51.3%	100.0%	21.1%	60.6%	87.3%	16.7%	0.0%	89.5%	69.5%	64.6%
	Upgrade	43.8%	38.2%	3.9%	46.4%	72.2%	100.0%	0.0%	18.2%	15.5%	0.0%	50.0%	10.5%	32.2%	19.4%	0.0%	0.0%	18.2%	40.0%	27.4%
Active	New Generation	15.3%	7.6%	17.1%	5.0%	0.0%	0.0%	66.7%	1.9%	8.3%	12.8%	0.0%	1.4%	27.9%	0.0%	0.0%	0.0%	0.0%	13.3%	18.0%
	Upgrade	31.3%	18.9%	22.8%	0.0%	0.0%	0.0%	33.3%	9.1%	13.8%	11.1%	25.0%	10.5%	46.0%	6.9%	30.0%	0.0%	9.1%	40.0%	21.3%

Table 12-24 shows the nameplate generating capacity of projects in the PJM generation queue by technology type and project classification. For example, the 404 new generation wind projects that have been withdrawn from the queue as of December 31, 2018, (as shown in Table 12-22) constitute 66,353.2 MW of nameplate capacity. The 489 new generation and upgrade combined cycle projects that have been withdrawn in the same time period constitute 205,440.3 MW of nameplate capacity.

Table 12-24 Status of all generation capacity (MW) in the PJM generation queue: January 1997 through December 2018

		Project MW																		
Project Status	Project Classification	Battery	CC	CT - Natural Gas	CT - Oil	CT - Other	Fuel Cell	Hydro - Pumped Storage	Hydro - Run of River	Nuclear	RICE - Natural Gas	RICE - Oil	RICE - Other	Solar	Steam - Coal	Steam - Natural Gas	Steam - Oil	Steam - Other	Wind	Total
In Service	New Generation	195.4	27,270.0	6,600.5	676.5	148.2	1.9	0.0	471.5	1,639.0	118.2	0.0	440.1	1,399.2	1,343.0	723.0	0.0	60.0	7,562.2	48,648.7
	Upgrade	42.4	5,231.8	2,323.5	127.8	12.3	0.0	356.0	373.6	2,282.8	15.7	23.3	49.9	19.4	883.5	131.5	0.0	605.3	0.5	12,479.3
Under Construction	New Generation	46.1	5,910.5	205.0	0.0	3.2	0.0	0.0	22.7	0.0	21.2	0.0	0.0	343.9	0.0	0.0	0.0	0.0	2,096.8	8,649.4
	Upgrade	0.0	900.1	48.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	13.9	48.0	0.0	0.0	62.5	219.5	1,292.0
Suspended	New Generation	43.3	3,222.0	68.8	0.0	0.0	0.0	0.0	0.0	0.0	79.6	0.0	0.0	424.9	0.0	0.0	0.0	16.0	1,340.3	5,194.9
	Upgrade	43.0	635.1	200.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	16.3	894.4
Withdrawn	New Generation	1,273.7	195,211.1	1,577.5	1,721.0	1,244.2	5.7	0.0	1,986.9	8,161.0	328.3	63.9	86.6	25,863.9	33,511.6	27.0	0.0	1,035.8	66,353.2	338,451.3
	Upgrade	301.1	10,229.3	273.5	589.0	72.5	0.9	0.0	57.1	916.0	0.0	13.0	6.0	835.1	865.0	0.0	0.0	37.1	437.0	14,632.6
Active	New Generation	842.3	31,299.3	3,692.9	14.0	0.0	0.0	1,000.0	15.0	28.0	90.3	0.0	2.0	31,255.8	0.0	0.0	0.0	0.0	20,645.6	88,885.2
	Upgrade	221.0	4,876.8	1,459.0	0.0	0.0	0.0	34.0	5.5	139.5	1.6	4.0	4.8	1,443.3	99.0	94.0	0.0	40.0	1,615.5	10,037.9
Total Projects	New Generation	2,400.7	262,912.9	12,144.7	2,411.5	1,395.6	7.6	1,000.0	2,496.1	9,828.0	637.6	63.9	528.7	59,287.6	34,854.6	750.0	0.0	1,111.8	97,998.1	489,829.4
	Upgrade	607.5	21,873.1	4,304.0	716.8	84.8	0.9	390.0	436.2	3,338.3	17.3	40.3	60.7	2,311.7	1,895.5	225.5	0.0	744.9	2,288.8	39,336.2

Table 12-25 shows the MW totals in Table 12-24 by share by classification as new generation or upgrade. Within a unit type the shares of upgrades add to 100 percent and the shares of new generation add to 100 percent. For example, 67.7 percent of wind project MW classified as new generation have been withdrawn from the queue between January 1, 1997, and December 31, 2018.

Table 12-25 Status of all generation queue projects as percent of total MW in project classification: January 1997 through December 2018

Project Status	Project Classification	Battery	CC	CT - Natural Gas	CT - Oil	CT - Other	Fuel Cell	Hydro - Pumped Storage	Hydro - Run of River	Nuclear	RICE - Natural Gas	RICE - Oil	RICE - Other	Solar	Steam - Coal	Steam - Natural Gas	Steam - Oil	Steam - Other	Wind	Total
		Percent of Total Projects by Classification																		
In Service	New Generation	8.1%	10.4%	54.3%	28.1%	10.6%	25.5%	0.0%	18.9%	16.7%	18.5%	0.0%	83.2%	2.4%	3.9%	96.4%	0.0%	5.4%	7.7%	9.9%
	Upgrade	7.0%	23.9%	54.0%	17.8%	14.5%	0.0%	91.3%	85.6%	68.4%	90.8%	57.8%	82.2%	0.8%	46.6%	58.3%	0.0%	81.3%	0.0%	31.7%
Under Construction	New Generation	1.9%	2.2%	1.7%	0.0%	0.2%	0.0%	0.0%	0.9%	0.0%	3.3%	0.0%	0.0%	0.6%	0.0%	0.0%	0.0%	0.0%	2.1%	1.8%
	Upgrade	0.0%	4.1%	1.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.6%	2.5%	0.0%	0.0%	8.4%	9.6%	3.3%
Suspended	New Generation	1.8%	1.2%	0.6%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	12.5%	0.0%	0.0%	0.7%	0.0%	0.0%	0.0%	1.4%	1.4%	1.1%
	Upgrade	7.1%	2.9%	4.6%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.7%	2.3%
Withdrawn	New Generation	53.1%	74.2%	13.0%	71.4%	89.2%	74.5%	0.0%	79.6%	83.0%	51.5%	100.0%	16.4%	43.6%	96.1%	3.6%	0.0%	93.2%	67.7%	69.1%
	Upgrade	49.6%	46.8%	6.4%	82.2%	85.5%	100.0%	0.0%	13.1%	27.4%	0.0%	32.3%	9.9%	36.1%	45.6%	0.0%	0.0%	5.0%	19.1%	37.2%
Active	New Generation	35.1%	11.9%	30.4%	0.6%	0.0%	0.0%	100.0%	0.6%	0.3%	14.2%	0.0%	0.4%	52.7%	0.0%	0.0%	0.0%	0.0%	21.1%	18.1%
	Upgrade	36.4%	22.3%	33.9%	0.0%	0.0%	0.0%	8.7%	1.3%	4.2%	9.2%	9.9%	7.9%	62.4%	5.2%	41.7%	0.0%	5.4%	70.6%	25.5%

Table 12-26 shows the project MW that entered the PJM generation queue by unit type and year of entry. Since 2016, 93.1 percent of all new projects entering the generation queue have been either combined cycle (29.3 percent), wind (20.6 percent) or solar projects (43.2 percent).

Table 12-26 Queue project MW by unit type and queue entry year: January 1997 through December 2018

Year	Battery	CC	CT - Natural Gas	CT - Oil	CT - Other	Fuel Cell	Hydro - Pumped Storage	Hydro - Run of River	Nuclear	RICE - Natural Gas	RICE - Oil	RICE - Other	Solar	Steam - Coal	Steam - Natural Gas	Steam - Oil	Steam - Other	Wind	Total
1997	0.0	4,148.0	321.0	315.0	0.0	0.0	0.0	0.0	50.0	0.0	0.0	0.0	0.0	6.0	0.0	0.0	0.0	0.0	4,840.0
1998	0.0	7,006.0	1,775.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	8,781.0
1999	0.0	29,412.7	2,412.1	0.0	10.0	0.0	0.0	196.0	45.0	0.0	0.0	0.0	0.0	47.0	0.0	0.0	525.0	115.4	32,763.2
2000	0.0	21,144.8	493.6	31.5	8.8	0.0	0.0	0.0	95.0	0.0	0.0	1.2	0.0	37.0	2.5	0.0	0.0	95.6	21,909.9
2001	0.0	25,411.7	264.0	0.0	0.0	0.0	0.0	107.0	90.0	0.0	0.0	15.6	0.0	1,244.6	10.0	0.0	0.0	252.9	27,395.8
2002	0.0	4,154.0	11.7	0.0	70.5	0.0	0.0	293.0	236.0	8.0	23.3	4.5	0.0	1,895.0	0.0	0.0	0.0	790.9	7,486.9
2003	0.0	2,361.4	10.0	8.0	0.8	0.0	0.0	2.0	0.0	29.0	0.0	27.5	0.0	522.0	0.0	0.0	165.0	997.0	4,122.7
2004	0.0	3,610.0	43.3	20.0	49.1	0.0	0.0	0.0	1,911.0	0.0	35.5	17.5	0.0	1,187.0	0.0	0.0	0.0	1,613.7	8,487.1
2005	0.0	5,824.6	961.0	281.0	51.4	0.0	340.0	174.2	242.0	21.5	0.0	65.1	0.0	6,360.0	0.0	0.0	24.0	6,020.0	20,364.9
2006	0.0	4,188.1	454.3	607.5	73.1	0.0	0.0	159.0	6,894.0	0.0	0.0	93.0	0.0	9,586.0	0.0	0.0	258.5	7,650.7	29,964.2
2007	0.0	13,944.6	941.2	215.9	149.5	0.0	16.0	255.4	368.0	0.0	0.0	56.5	3.3	9,078.0	190.0	0.0	50.5	18,525.6	43,794.4
2008	121.0	26,001.0	129.7	1,113.0	488.8	0.0	0.0	1,254.5	105.0	6.0	0.0	32.0	66.3	1,198.0	0.0	0.0	192.3	11,199.7	41,907.3
2009	34.0	5,548.4	14.0	66.0	214.2	0.0	0.0	133.9	1,933.8	4.5	16.0	15.2	636.5	1,273.0	5.5	0.0	148.0	6,672.6	16,715.6
2010	72.4	9,185.4	176.0	7.9	117.3	0.0	0.0	132.6	426.0	0.0	2.4	57.8	3,690.0	64.0	0.0	0.0	173.5	9,940.4	24,045.7
2011	24.1	20,354.5	29.5	0.0	174.6	0.0	0.0	30.0	182.0	0.0	14.0	75.3	2,022.9	357.0	0.0	0.0	49.0	5,576.4	28,889.3
2012	142.6	18,014.8	282.1	42.5	48.4	0.0	0.0	11.8	369.0	37.2	0.0	4.0	286.6	1,837.0	0.0	0.0	143.1	1,529.8	22,748.8
2013	217.4	11,168.1	526.8	5.0	11.2	0.0	0.0	89.4	102.0	59.7	0.0	1.6	231.7	158.0	40.0	0.0	44.7	1,407.9	14,063.4
2014	246.9	11,704.5	1,532.5	401.0	7.7	0.0	0.0	60.5	0.0	48.0	0.0	17.7	1,445.7	1,730.5	27.0	0.0	43.1	1,763.7	19,028.8
2015	546.9	27,540.8	1,324.5	0.0	0.9	2.3	34.0	0.0	0.0	320.4	13.0	31.4	2,931.6	47.0	606.5	0.0	0.0	2,160.6	35,559.7
2016	111.1	18,804.5	1,392.0	0.0	0.0	3.4	0.0	12.5	50.3	23.5	0.0	38.9	11,771.5	80.0	77.0	0.0	0.0	3,467.5	35,832.2
2017	24.6	5,465.8	702.0	0.0	4.1	2.9	0.0	20.5	39.1	97.1	0.0	33.8	13,895.2	14.0	17.0	0.0	0.0	5,602.0	25,918.2
2018	1,467.2	9,792.4	2,652.4	14.0	0.0	0.0	1,000.0	0.0	28.1	0.0	0.0	0.8	24,617.9	29.0	0.0	0.0	40.0	14,904.5	54,546.3
Total	3,008.2	284,786.0	16,448.7	3,128.3	1,480.3	8.5	1,390.0	2,932.3	13,166.3	654.9	104.2	589.4	61,599.3	36,750.1	975.5	0.0	1,856.7	100,286.9	529,165.5

Combined Cycle Project Analysis

Table 12-27 shows the status of all combined cycle projects by number of projects that entered PJM generation queues from January 1, 1997, through December 31, 2018, by zone. Of the 111 combined cycle projects classified either as new generation or upgrade currently active, suspended or under construction in the PJM generation queue, 48 projects (43.2 percent) are located within AEP, ComEd and APS.

Table 12-27 Status of all combined cycle queue projects by zone (number of projects): January 1997 through December 2018

Project Status	Project Classification	AECO	AEP	APS	ATSI	BGE	ComEd	DAY	DEOK	DLCO	Dominion	DPL	EKPC	JCPL	Met-Ed	OVEC	PECO	PENELEC	Pepco	PPL	PSEG	RECO	Total
		Number of Projects																					
In Service	New Generation	1	4	1	2	2	1	0	2	0	6	2	0	7	3	0	4	1	3	10	5	0	54
	Upgrade	2	8	5	3	0	3	0	0	0	12	5	0	4	1	0	9	3	2	5	13	0	75
Under Construction	New Generation	1	0	1	0	0	0	0	0	0	1	0	0	0	1	0	1	1	1	0	1	0	8
	Upgrade	0	2	0	0	0	1	0	0	0	0	0	0	1	1	0	3	1	1	2	1	0	13
Suspended	New Generation	0	1	1	0	0	0	0	0	0	0	0	0	1	0	0	0	1	1	0	0	0	5
	Upgrade	0	0	1	0	0	0	0	0	0	0	1	0	1	0	0	0	0	2	0	0	0	5
Withdrawn	New Generation	20	18	40	12	8	11	0	1	2	17	17	3	24	25	0	43	39	33	39	52	2	406
	Upgrade	6	7	5	3	0	3	0	1	0	10	4	0	5	7	0	3	5	3	6	15	0	83
Active	New Generation	2	8	7	5	0	7	1	0	0	2	0	0	1	0	0	0	0	0	2	4	0	39
	Upgrade	3	6	8	3	0	5	0	0	0	3	0	0	3	2	0	1	2	1	3	1	0	41
Total Projects	New Generation	24	31	50	19	10	19	1	3	2	26	19	3	33	29	0	48	42	38	51	62	2	512
	Upgrade	11	23	19	9	0	12	0	1	0	25	10	0	14	11	0	16	11	9	16	30	0	217

Table 12-28 shows the status of all combined cycle projects by MW that entered PJM generation queues from January 1, 1997 through December 31, 2018, by zone. Of the 46,843.8 MW of combined cycle projects classified either as new generation or upgrade currently active, suspended or under construction in the PJM generation queue, 22,320.9 MW (47.6 percent) are located within AEP, ComEd and APS.

Table 12-28 Status of all combined cycle queue projects by zone (MW): January 1997 through December 2018

		Project MW													
Project Status	Project Classification	AECO	AEP	APS	ATSI	BGE	ComEd	DAY	DEOK	DLCO	Dominion	DPL	EKPC	JCPL	Met-Ed
In Service	New Generation	650.0	3,032.0	525.0	1,599.0	140.0	600.0	0.0	533.0	0.0	4,173.1	319.2	0.0	1,665.8	2,107.0
	Upgrade	220.0	230.0	670.0	306.0	0.0	621.0	0.0	0.0	0.0	853.0	102.0	0.0	110.0	10.0
Under Construction	New Generation	452.0	0.0	930.0	0.0	0.0	0.0	0.0	0.0	0.0	1,681.0	0.0	0.0	0.0	450.0
	Upgrade	0.0	100.0	0.0	0.0	0.0	12.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	35.0
Suspended	New Generation	0.0	585.0	1,140.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	440.0	0.0
	Upgrade	0.0	0.0	20.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	451.0	0.0	20.0	0.0
Withdrawn	New Generation	7,144.4	11,249.5	16,982.1	7,471.0	3,122.1	6,225.3	0.0	134.5	665.0	11,261.0	5,436.4	991.8	12,552.6	13,001.0
	Upgrade	115.4	711.0	579.0	86.0	0.0	1,375.0	0.0	36.0	0.0	580.4	668.0	0.0	253.0	1,742.0
Active	New Generation	946.0	6,589.0	4,606.0	5,217.0	0.0	4,954.9	1,150.0	0.0	0.0	2,660.0	0.0	0.0	570.0	0.0
	Upgrade	50.6	742.0	899.7	588.0	0.0	1,741.7	0.0	0.0	0.0	110.0	0.0	0.0	145.0	113.9
Total Projects	New Generation	9,192.4	21,455.5	24,183.1	14,287.0	3,262.1	11,780.2	1,150.0	667.5	665.0	19,775.1	5,755.6	991.8	15,228.4	15,558.0
	Upgrade	386.0	1,783.0	2,168.7	980.0	0.0	3,750.3	0.0	36.0	0.0	1,543.4	1,221.0	0.0	528.0	1,900.9

		Project MW							
Project Status	Project Classification	OVEC	PECO	PENELEC	Pepco	PPL	PSEG	RECO	Total
In Service	New Generation	0.0	1,905.0	850.0	1,540.5	5,750.0	1,880.5	0.0	27,270.0
	Upgrade	0.0	853.5	92.3	89.1	229.0	845.9	0.0	5,231.8
Under Construction	New Generation	0.0	760.0	1,050.0	19.5	0.0	568.0	0.0	5,910.5
	Upgrade	0.0	155.0	50.0	64.5	483.0	0.0	0.0	900.1
Suspended	New Generation	0.0	0.0	163.0	894.0	0.0	0.0	0.0	3,222.0
	Upgrade	0.0	0.0	0.0	144.1	0.0	0.0	0.0	635.1
Withdrawn	New Generation	0.0	23,340.0	15,931.0	20,414.2	16,785.7	22,496.7	6.9	195,211.1
	Upgrade	0.0	240.0	1,040.6	85.0	500.0	2,217.9	0.0	10,229.3
Active	New Generation	0.0	0.0	0.0	0.0	1,515.0	3,091.4	0.0	31,299.3
	Upgrade	0.0	67.0	85.0	75.0	207.8	51.1	0.0	4,876.8
Total Projects	New Generation	0.0	26,005.0	17,994.0	22,868.2	24,050.7	28,036.6	6.9	262,912.9
	Upgrade	0.0	1,315.5	1,267.9	457.7	1,419.8	3,114.9	0.0	21,873.1

Combustion Turbine - Natural Gas Project Analysis

Table 12-29 shows the status of all combustion turbine natural gas projects by number of projects that entered PJM generation queues from January 1, 1997, through December 31, 2018, by zone. Of the 50 combustion turbine natural gas projects classified either as new generation or upgrade currently active, suspended or under construction in the PJM generation queue, 26 projects (52.0 percent) are located within AEP, ComEd and APS.

Table 12-29 Status of all combustion turbine - natural gas generation queue projects by zone (number of projects): January 1997 through December 2018

		Number of Projects																				
Project Status	Project Classification	AECO	AEP	APS	ATSI	BGE	ComEd	DAY	DEOK	DLCO	Dominion	DPL	EKPC	JCPL	Met-Ed	OVEC	PECO	PENELEC	Pepco	PPL	PSEG	RECO	Total
In Service	New Generation	5	0	6	0	3	0	0	0	0	2	7	0	3	1	0	2	4	2	4	9	0	48
	Upgrade	4	7	6	1	0	9	6	0	0	24	7	0	0	1	0	2	2	3	4	14	0	90
Under Construction	New Generation	0	0	0	0	0	0	0	0	1	0	0	0	0	0	0	0	0	0	0	0	0	1
	Upgrade	0	0	0	0	0	1	0	0	0	0	0	0	1	0	0	0	0	0	0	0	0	2
Suspended	New Generation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	3	0	0	0	0	3
	Upgrade	0	0	0	0	0	0	0	0	0	0	0	0	1	0	0	0	0	0	0	0	0	1
Withdrawn	New Generation	1	3	0	0	0	1	0	0	0	2	0	0	0	0	0	1	2	0	1	5	0	16
	Upgrade	1	1	0	1	0	0	0	0	0	0	0	0	0	1	0	0	1	0	0	0	0	5
Active	New Generation	1	3	0	0	2	2	0	0	0	3	0	1	0	0	0	1	1	0	0	0	0	14
	Upgrade	1	2	5	1	0	13	0	0	0	5	0	0	0	0	0	1	1	0	0	0	0	29
Total Projects	New Generation	7	6	6	0	5	3	0	0	1	7	7	1	3	1	0	4	10	2	5	14	0	82
	Upgrade	6	10	11	3	0	23	6	0	0	29	7	0	2	2	0	3	4	3	4	14	0	127

Table 12-30 shows the status of all combustion turbine natural gas projects by MW that entered PJM generation queues from January 1, 1997 through December 31, 2018, by zone. Of the 5,673.7 MW of combustion turbine natural gas projects classified either as new generation or upgrade currently active, suspended or under construction in the PJM generation queue, 2,849.0 MW (50.2 percent) are located within AEP, ComEd and APS.

Table 12-30 Status of all combustion turbine – natural gas queue projects by zone (MW): January 1997 through December 2018

		Project MW														
Project Status	Project Classification	AECO	AEP	APS	ATSI	BGE	ComEd	DAY	DEOK	DLCO	Dominion	DPL	EKPC	JCPL	Met-Ed	OVEC
In Service	New Generation	360.7	0.0	1,176.0	0.0	23.0	0.0	0.0	0.0	0.0	1,015.0	1,491.0	0.0	522.1	10.0	0.0
	Upgrade	43.7	190.0	187.7	40.0	0.0	257.0	60.0	0.0	0.0	887.7	86.0	0.0	0.0	34.1	0.0
Under Construction	New Generation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	205.0	0.0	0.0	0.0	0.0	0.0	0.0
	Upgrade	0.0	0.0	0.0	0.0	0.0	48.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Suspended	New Generation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Upgrade	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	200.0	0.0	0.0
Withdrawn	New Generation	7.5	66.0	0.0	0.0	0.0	10.0	0.0	0.0	0.0	75.5	0.0	0.0	0.0	0.0	0.0
	Upgrade	7.5	6.0	0.0	25.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Active	New Generation	230.0	1,453.0	0.0	0.0	153.6	230.0	0.0	0.0	0.0	1,061.3	0.0	73.0	0.0	0.0	0.0
	Upgrade	158.0	38.0	120.0	70.0	0.0	960.0	0.0	0.0	0.0	95.0	0.0	0.0	0.0	0.0	0.0
Total Projects	New Generation	598.2	1,519.0	1,176.0	0.0	176.6	240.0	0.0	0.0	205.0	2,151.8	1,491.0	73.0	522.1	10.0	0.0
	Upgrade	209.2	234.0	307.7	135.0	0.0	1,265.0	60.0	0.0	0.0	982.7	86.0	0.0	200.0	34.1	0.0

		Project MW						
Project Status	Project Classification	PECO	PENELEC	Pepco	PPL	PSEG	RECO	Total
In Service	New Generation	559.0	361.9	5.0	150.9	925.9	0.0	6,600.5
	Upgrade	13.0	25.0	32.0	252.3	215.0	0.0	2,323.5
Under Construction	New Generation	0.0	0.0	0.0	0.0	0.0	0.0	205.0
	Upgrade	0.0	0.0	0.0	0.0	0.0	0.0	48.0
Suspended	New Generation	0.0	68.8	0.0	0.0	0.0	0.0	68.8
	Upgrade	0.0	0.0	0.0	0.0	0.0	0.0	200.0
Withdrawn	New Generation	0.5	258.0	0.0	19.9	1,140.1	0.0	1,577.5
	Upgrade	0.0	235.0	0.0	0.0	0.0	0.0	273.5
Active	New Generation	29.0	463.0	0.0	0.0	0.0	0.0	3,692.9
	Upgrade	0.0	18.0	0.0	0.0	0.0	0.0	1,459.0
Total Projects	New Generation	588.5	1,151.7	5.0	170.8	2,066.0	0.0	12,144.7
	Upgrade	13.0	278.0	32.0	252.3	215.0	0.0	4,304.0

Wind Project Analysis

Table 12-31 shows the status of all wind generation projects by number of projects that entered PJM generation queues from January 1, 1997, through December 31, 2018, by zone. Of the 84 wind projects to achieve in service status, 48 projects (57.1 percent) are located within AEP, ComEd and APS. Of the 123 wind projects currently active, suspended or under construction in the PJM generation queue, 94 projects (76.4 percent) are located within AEP, ComEd and APS.

Table 12-31 Status of all wind generation queue projects by zone (number of projects): January 1997 through December 2018

		Number of Projects																					
Project Status	Project Classification	AECO	AEP	APS	ATSI	BGE	ComEd	DAY	DEOK	DLCO	Dominion	DPL	EKPC	JCPL	Met-Ed	OVEC	PECO	PENELEC	Pepco	PPL	PSEG	RECO	Total
In Service	New Generation	1	13	14	0	0	19	0	0	0	1	0	0	0	0	0	0	22	0	8	0	0	78
	Upgrade	0	0	0	0	0	2	0	0	0	0	0	0	0	0	0	0	4	0	0	0	0	6
Under Construction	New Generation	0	2	3	0	0	3	0	0	0	3	0	0	0	0	0	0	1	0	0	0	0	12
	Upgrade	0	0	1	0	0	1	0	0	0	1	0	0	0	0	0	0	0	0	0	0	0	3
Suspended	New Generation	0	4	3	0	0	0	0	0	0	1	0	0	0	0	0	0	1	0	1	0	0	10
	Upgrade	0	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1
Withdrawn	New Generation	15	95	41	8	0	95	14	0	0	18	10	1	0	0	0	0	63	0	43	1	0	404
	Upgrade	1	0	6	0	0	3	0	0	0	2	0	0	0	0	0	0	6	0	2	0	0	20
Active	New Generation	2	25	4	3	0	30	1	0	0	3	3	0	3	0	0	0	0	0	3	0	0	77
	Upgrade	1	3	4	0	0	10	0	0	0	0	0	0	0	0	0	0	2	0	0	0	0	20
Total Projects	New Generation	18	139	65	11	0	147	15	0	0	26	13	1	3	0	0	0	87	0	55	1	0	581
	Upgrade	2	3	12	0	0	16	0	0	0	3	0	0	0	0	0	0	12	0	2	0	0	50

Table 12-32 shows the status of all wind projects by MW that entered PJM generation queues from January 1, 1997 through December 31, 2018, by zone. Of the 7,562.7 MW of wind generation capacity to achieve the in service status, 6,230.7 MW (84.4 percent) of nameplate capacity is located within AEP, ComEd and APS. Of the 25,934.0 MW of wind generation capacity currently active, suspended or under construction in the PJM generation queue, 17,114.3 MW of generation capacity (66.0 percent) is located within AEP, ComEd and APS.

Table 12-32 Status of all wind generation queue projects by zone (MW): January 1997 through December 2018

		Project MW														
Project Status	Project Classification	AECO	AEP	APS	ATSI	BGE	ComEd	DAY	DEOK	DLCO	Dominion	DPL	EKPC	JCPL	Met-Ed	OVEC
In Service	New Generation	7.5	2,538.7	1,004.0	0.0	0.0	2,688.0	0.0	0.0	0.0	102.5	0.0	0.0	0.0	0.0	0.0
	Upgrade	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Under Construction	New Generation	0.0	350.0	298.0	0.0	0.0	766.5	0.0	0.0	0.0	612.3	0.0	0.0	0.0	0.0	0.0
	Upgrade	0.0	0.0	0.0	0.0	0.0	187.5	0.0	0.0	0.0	32.0	0.0	0.0	0.0	0.0	0.0
Suspended	New Generation	0.0	722.0	343.7	0.0	0.0	0.0	0.0	0.0	0.0	76.6	0.0	0.0	0.0	0.0	0.0
	Upgrade	0.0	0.0	16.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Withdrawn	New Generation	3,626.4	19,653.2	3,134.1	1,295.6	0.0	22,521.7	2,028.0	0.0	0.0	2,588.1	2,816.8	150.3	0.0	0.0	0.0
	Upgrade	0.0	0.0	100.0	0.0	0.0	5.7	0.0	0.0	0.0	82.0	0.0	0.0	0.0	0.0	0.0
Active	New Generation	516.0	5,117.3	350.0	816.1	0.0	7,473.0	100.0	0.0	0.0	2,400.3	599.8	0.0	3,016.0	0.0	0.0
	Upgrade	5.0	500.0	94.4	0.0	0.0	895.7	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total Projects	New Generation	4,149.9	28,381.2	5,129.8	2,111.7	0.0	33,449.1	2,128.0	0.0	0.0	5,779.8	3,416.6	150.3	3,016.0	0.0	0.0
	Upgrade	5.0	500.0	210.7	0.0	0.0	1,088.9	0.0	0.0	0.0	114.0	0.0	0.0	0.0	0.0	0.0

		Project MW						
Project Status	Project Classification	PECO	PENELEC	Pepco	PPL	PSEG	RECO	Total
In Service	New Generation	0.0	995.0	0.0	226.5	0.0	0.0	7,562.2
	Upgrade	0.0	0.5	0.0	0.0	0.0	0.0	0.5
Under Construction	New Generation	0.0	70.0	0.0	0.0	0.0	0.0	2,096.8
	Upgrade	0.0	0.0	0.0	0.0	0.0	0.0	219.5
Suspended	New Generation	0.0	100.0	0.0	98.0	0.0	0.0	1,340.3
	Upgrade	0.0	0.0	0.0	0.0	0.0	0.0	16.3
Withdrawn	New Generation	0.0	5,277.0	0.0	3,242.1	20.0	0.0	66,353.2
	Upgrade	0.0	243.4	0.0	6.0	0.0	0.0	437.0
Active	New Generation	0.0	0.0	0.0	257.3	0.0	0.0	20,645.6
	Upgrade	0.0	120.3	0.0	0.0	0.0	0.0	1,615.5
Total Projects	New Generation	0.0	6,442.0	0.0	3,823.9	20.0	0.0	97,998.1
	Upgrade	0.0	364.2	0.0	6.0	0.0	0.0	2,288.8

Solar Project Analysis

Table 12-33 shows the status of all solar generation projects by number of projects that entered PJM generation queues from January 1, 1997, through December 31, 2018, by zone. Of the 146 solar projects to achieve in service status, 9 projects (6.2 percent) are located within AEP, ComEd and APS. Of the 532 solar projects currently active, suspended or under construction in the PJM generation queue, 154 projects (28.9 percent) are located within AEP, ComEd and APS.

Table 12-33 Status of all solar generation queue projects by zone (number of projects): January 1997 through December 2018

		Number of Projects																					
Project Status	Project Classification	AECO	AEP	APS	ATSI	BGE	ComEd	DAY	DEOK	DLCO	Dominion	DPL	EKPC	JCPL	Met-Ed	OVEC	PECO	PENELEC	Pepco	PPL	PSEG	RECO	Total
In Service	New Generation	7	4	4	0	1	1	1	0	0	19	9	0	42	0	0	1	0	0	2	39	0	130
	Upgrade	0	0	0	0	0	0	0	0	0	2	8	0	6	0	0	0	0	0	0	0	0	16
Under Construction	New Generation	0	0	1	0	0	0	0	0	0	4	4	0	4	0	0	0	0	0	0	6	0	19
	Upgrade	0	0	0	0	0	0	0	0	0	2	1	0	0	0	0	0	0	0	0	0	0	3
Suspended	New Generation	0	4	19	0	0	0	1	0	0	1	0	0	5	1	0	0	0	0	0	1	0	32
	Upgrade	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Withdrawn	New Generation	159	83	58	9	12	30	14	12	0	146	116	3	167	12	0	6	13	13	28	70	0	951
	Upgrade	2	2	1	0	0	2	0	0	0	11	1	0	8	0	0	0	0	0	0	1	0	28
Active	New Generation	16	80	19	9	0	23	11	3	1	166	40	10	6	13	0	1	8	13	7	11	1	438
	Upgrade	0	6	1	1	0	1	1	3	1	18	1	0	2	2	0	0	0	1	1	0	1	40
Total Projects	New Generation	182	171	101	18	13	54	27	15	1	336	169	13	224	26	0	8	21	26	37	127	1	1,570
	Upgrade	2	8	2	1	0	3	1	3	1	33	11	0	16	2	0	0	0	1	1	1	1	87

Table 12-34 shows the status of all solar projects by MW that entered PJM generation queues from January 1, 1997 through December 31, 2018, by zone. Of the 1,418.6 MW of solar generation capacity to achieve in service status, 76.7 MW (5.4 percent) of nameplate capacity is located within AEP, ComEd and APS. Of the 33,481.7 MW of solar generation capacity currently active, suspended or under construction in the PJM generation queue, 11,756.1 MW of generation capacity (35.1 percent) is located within AEP, ComEd and APS.

Table 12-34 Status of all solar generation queue projects by zone (MW): January 1997 through December 2018

		Project MW														
Project Status	Project Classification	AECO	AEP	APS	ATSI	BGE	ComEd	DAY	DEOK	DLCO	Dominion	DPL	EKPC	JCPL	Met-Ed	OVEC
In Service	New Generation	57.3	14.7	53.0	0.0	1.1	9.0	2.5	0.0	0.0	636.1	118.4	0.0	295.3	0.0	0.0
	Upgrade	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	3.1	0.0	0.0	16.3	0.0	0.0
Under Construction	New Generation	0.0	0.0	10.0	0.0	0.0	0.0	0.0	0.0	0.0	194.9	37.0	0.0	71.9	0.0	0.0
	Upgrade	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	13.9	0.0	0.0	0.0	0.0	0.0
Suspended	New Generation	0.0	40.0	313.3	0.0	0.0	0.0	20.0	0.0	0.0	5.0	0.0	0.0	37.6	3.0	0.0
	Upgrade	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Withdrawn	New Generation	1,665.3	6,470.6	1,486.4	271.1	53.3	1,816.8	523.9	279.4	0.0	8,539.0	1,540.7	189.9	1,348.8	467.0	0.0
	Upgrade	10.0	106.0	0.0	0.0	0.0	20.0	0.0	0.0	0.0	674.0	0.0	0.0	23.8	0.0	0.0
Active	New Generation	311.5	7,359.9	962.4	979.1	0.0	2,598.5	1,096.5	295.0	11.7	13,797.1	1,385.2	986.0	50.9	501.6	0.0
	Upgrade	0.0	377.0	75.0	20.0	0.0	20.0	20.0	85.0	8.3	737.1	20.0	0.0	17.3	40.0	0.0
Total Projects	New Generation	2,034.1	13,885.3	2,825.1	1,250.2	54.4	4,424.3	1,642.9	574.4	11.7	23,172.1	3,081.3	1,175.9	1,804.5	971.6	0.0
	Upgrade	10.0	483.0	75.0	20.0	0.0	40.0	20.0	85.0	8.3	1,428.1	20.0	0.0	57.4	40.0	0.0

		Project MW						
Project Status	Project Classification	PECO	PENELEC	Pepco	PPL	PSEG	RECO	Total
In Service	New Generation	3.3	0.0	0.0	15.0	193.5	0.0	1,399.2
	Upgrade	0.0	0.0	0.0	0.0	0.0	0.0	19.4
Under Construction	New Generation	0.0	0.0	0.0	0.0	30.1	0.0	343.9
	Upgrade	0.0	0.0	0.0	0.0	0.0	0.0	13.9
Suspended	New Generation	0.0	0.0	0.0	0.0	6.0	0.0	424.9
	Upgrade	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Withdrawn	New Generation	51.4	171.7	128.1	383.7	476.7	0.0	25,863.9
	Upgrade	0.0	0.0	0.0	0.0	1.3	0.0	835.1
Active	New Generation	18.0	458.8	172.9	174.6	56.2	40.0	31,255.8
	Upgrade	0.0	0.0	3.6	0.0	0.0	20.0	1,443.3
Total Projects	New Generation	72.7	630.5	301.0	573.3	762.5	40.0	59,287.6
	Upgrade	0.0	0.0	3.6	0.0	1.3	20.0	2,311.7

Relationship Between Project Developer and Transmission Owner

A transmission owner (TO) is an "entity that owns, leases or otherwise has a possessory interest in facilities used for the transmission of electric energy in interstate commerce under the tariff."[37] Where the transmission owner is a vertically integrated company that also owns generation, there is a potential conflict of interest when the transmission owner evaluates the interconnection requirements of new generation which is a competitor to the generation of the parent company and when the transmission owner evaluates the interconnection requirements of new generation which is part of the same company as the transmission owner. There is also a potential conflict of interest when the transmission owner evaluates the interconnection requirements of a merchant transmission developer which is a competitor of the transmission owner. The MMU recommends outsourcing interconnection studies to an independent party to avoid potential conflicts of interest.

Table 12-35 shows the relationship between the project developer and Transmission Owner for all project MW that have entered the PJM generation queue from January 1, 1997, through December 31, 2018, by transmission owner and unit type. A project where the developer is affiliated with the Transmission Owner is classified as related. A project where the developer is not affiliated with the Transmission Owner is classified as unrelated. For example, 36.0 MW of combined cycle generation projects that have entered the PJM generation queue in DEOK were projects developed by Duke Energy or subsidiaries of Duke Energy, the Transmission Owner for DEOK. These project MW are classified as related. There have been 667.5 MW of combined cycle projects that have entered the PJM generation queue in DEOK by developers not affiliated with Duke Energy. These project MW are classified as unrelated.

Of the 529,165.5 MW that have entered the queue during the time period of January 1, 1997, through December 31, 2018, 62,049.7 MW (11.7 percent) have been submitted by Transmission Owners building in their own service territory. PSEG is the Transmission Owner with the highest percentage of affiliates building in their own service territory. Of the 36,399.5 MW that entered the queue during the time period of January 1, 1997, through December 31, 2018, 14,279.0 MW (39.2 percent) have been submitted by PSEG or one of their affiliated companies.

37 See OATT § 1 (Transmission Owner).

Table 12-35 Relationship between project developer and Transmission Owner for all interconnection queue projects MW by unit type: December 31, 2018

Parent Company	Transmission Owner	Related to Developer	Number of Projects	Battery	CC	CT - Natural Gas	CT - Oil	CT - Other	Fuel Cell	Hydro - Pumped Storage	Hydro - Run of River	Nuclear	RICE - Natural Gas	RICE - Oil	RICE - Other	Solar	Steam - Coal	Steam - Natural Gas	Steam - Oil	Steam - Other	Wind	Total
				MW by Unit Type																		
AEP	AEP	Related	48	16.0	680.0	0.0	0.0	0.0	0.0	34.0	0.0	214.0	0.0	0.0	0.0	142.7	3,918.0	90.0	0.0	0.0	0.0	5,094.7
		Unrelated	486	478.0	22,558.5	1,753.0	7.5	127.3	0.0	0.0	448.4	0.0	12.0	0.0	75.4	14,225.6	10,368.0	0.0	0.0	492.0	28,881.2	79,426.8
AES	DAY	Related	13	20.0	0.0	38.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	21.5	1,347.5	0.0	0.0	0.0	0.0	1,427.0
		Unrelated	49	39.9	1,150.0	22.0	0.0	1.9	0.0	0.0	0.0	0.0	0.0	0.0	10.0	1,641.4	0.0	0.0	0.0	0.0	2,128.0	4,993.2
DLCO	DLCO	Related	0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	22	20.0	665.0	205.0	40.0	19.2	0.0	0.0	106.0	1,879.0	0.0	0.0	0.0	20.0	2,810.0	0.0	0.0	0.0	0.0	5,764.2
Dominion	Dominion	Related	92	0.0	12,274.0	908.7	100.0	0.0	0.0	340.0	0.0	1,944.0	0.0	0.0	60.0	901.6	301.0	0.0	0.0	4.0	146.0	16,979.3
		Unrelated	472	140.0	9,044.5	2,225.8	0.5	227.3	0.0	0.0	35.0	0.0	0.0	10.0	119.4	23,698.6	20.0	0.0	0.0	316.3	5,747.8	41,585.2
Duke	DEOK	Related	7	23.8	36.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	6.4	0.0	0.0	0.0	0.0	0.0	66.2
		Unrelated	26	16.0	667.5	0.0	0.0	0.0	0.0	0.0	112.0	0.0	0.0	0.0	4.8	653.0	120.0	0.0	0.0	0.0	0.0	1,573.3
EKPC	EKPC	Related	2	0.0	821.8	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	821.8
		Unrelated	16	0.0	170.0	73.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1,175.9	0.0	0.0	0.0	0.0	150.3	1,569.2
Exelon	AECO	Related	5	0.0	730.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	8.3	0.0	0.0	0.0	0.0	0.0	738.3
		Unrelated	286	141.0	8,848.4	807.4	380.0	20.7	2.8	0.0	0.0	0.0	2.0	5.0	10.3	2,035.8	15.0	5.5	0.0	10.0	4,154.9	16,438.8
	BGE	Related	14	20.0	250.0	10.0	0.0	0.0	0.0	0.0	0.0	108.5	0.0	0.0	8.5	20.0	10.0	101.0	0.0	0.0	0.0	528.0
		Unrelated	57	40.6	3,012.1	166.6	18.0	133.0	0.0	0.0	0.4	3,280.0	1.3	0.0	0.0	34.4	0.0	2.5	0.0	25.0	0.0	6,713.9
	ComEd	Related	16	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1,185.0	0.0	0.0	0.0	9.0	0.0	0.0	0.0	0.0	0.0	1,194.0
		Unrelated	338	411.1	15,530.5	1,505.0	42.0	65.2	0.0	0.0	22.7	0.0	35.0	0.0	67.7	4,455.3	1,926.0	91.0	0.0	90.0	34,538.0	58,779.5
	DPL	Related	7	0.0	1,365.0	351.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	7.4	0.0	0.0	0.0	0.0	0.0	1,723.4
		Unrelated	282	143.0	5,611.6	1,226.0	600.9	42.6	0.0	0.0	0.0	0.0	0.0	0.0	84.6	3,093.9	653.0	15.0	0.0	65.0	3,416.6	14,952.2
	PECO	Related	33	40.0	6,965.0	5.0	89.5	0.0	0.0	0.0	265.0	437.8	0.0	0.0	0.0	0.0	7.0	0.0	0.0	0.0	0.0	7,809.3
		Unrelated	80	5.3	20,355.5	596.5	2.0	15.0	0.0	0.0	0.0	0.0	0.0	17.0	3.7	72.7	0.0	0.0	0.0	0.0	0.0	21,067.7
	Pepco	Related	0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	90	20.0	23,325.9	37.0	30.0	9.0	0.0	0.0	0.0	1,640.0	32.0	0.0	3.5	304.6	0.0	0.0	0.0	0.0	0.0	25,402.0
First Energy	APS	Related	4	0.0	1,453.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1,710.0	0.0	0.0	0.0	0.0	3,163.0
		Unrelated	355	330.9	24,898.8	1,483.7	0.0	84.4	0.0	0.0	623.3	0.0	140.0	53.8	25.4	2,900.1	4,092.0	0.0	0.0	184.4	5,340.5	40,157.3
	ATSI	Related	6	0.0	1,678.0	0.0	0.0	0.0	0.0	0.0	0.0	16.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1,694.0
		Unrelated	77	56.1	13,589.0	135.0	5.0	166.4	0.0	0.0	0.0	0.0	59.7	0.0	6.9	1,270.2	0.0	16.5	0.0	0.0	2,111.7	17,416.5
	JCPL	Related	2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	20.0	0.0	0.0	0.0	0.0	12.0	0.0	0.0	0.0	0.0	0.0	32.0
		Unrelated	348	382.8	15,756.4	722.1	0.0	4.8	0.8	0.0	1.6	0.0	0.6	0.0	12.8	1,849.8	0.0	0.0	0.0	30.0	3,016.0	21,777.7
	Met-Ed	Related	0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	102	23.0	17,458.9	44.1	1,196.9	52.1	0.0	0.0	0.0	93.0	0.0	8.0	23.2	1,011.6	0.0	0.0	0.0	84.0	0.0	19,994.8
	PENELEC	Related	4	0.0	534.0	5.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1,860.0	0.0	0.0	0.0	0.0	2,399.0
		Unrelated	245	97.4	18,727.9	1,424.7	0.0	214.4	0.0	16.0	46.3	0.0	341.8	8.0	14.8	630.5	561.0	590.0	0.0	525.0	6,806.2	30,003.8
OVEC	OVEC	Related	0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
PPL	PPL	Related	21	0.0	2,261.0	0.0	0.0	0.0	0.0	0.0	109.0	1,600.0	0.0	0.0	0.0	19.8	111.0	0.0	0.0	0.0	0.0	4,100.8
		Unrelated	233	528.8	23,209.5	423.1	8.0	234.5	0.0	1,000.0	142.6	388.0	19.9	2.4	44.7	553.5	6,896.6	0.0	0.0	31.0	3,829.9	37,312.5
PSEG	PSEG	Related	106	0.0	11,836.1	1,818.1	0.0	0.0	0.0	0.0	0.0	381.0	0.0	0.0	0.0	175.8	24.0	44.0	0.0	0.0	0.0	14,279.0
		Unrelated	196	14.5	19,315.4	462.9	608.0	62.5	4.9	0.0	1,000.0	0.0	10.6	0.0	13.7	588.0	0.0	20.0	0.0	0.0	20.0	22,120.5
Con Ed	RECO	Related	0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	4	0.0	6.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	60.0	0.0	0.0	0.0	0.0	0.0	66.9
Total		Related	380	119.8	40,883.9	3,135.8	189.5	0.0	0.0	374.0	394.0	5,886.3	0.0	0.0	68.5	1,324.4	9,288.5	235.0	0.0	4.0	146.0	62,049.7
		Unrelated	3764	2,888.4	243,902.1	13,312.9	2,938.8	1,480.3	8.5	1,016.0	2,538.3	7,280.0	654.9	104.2	520.9	60,274.9	27,461.6	740.5	0.0	1,852.7	100,140.9	467,115.8

Combined Cycle Project Developer and Transmission Owner Relationships

Table 12-36 shows the relationship between the project developer and Transmission Owner for all combined cycle project MW that have entered the PJM generation queue from January 1, 1997 through December 31, 2018, by transmission owner and project status. Of the 39,312.4 combined cycle project MW that have achieved in service or under construction status during this time period, 9,156.0 MW (23.3 percent) have been developed by Transmission Owners building in their own service territory. EKPC is the Transmission Owner with the highest percentage of affiliates building combined cycle projects in their own service territory. Of the 991.8 MW that entered the queue during the time period of January 1, 1997, through December 31, 2018, 821.8 MW (82.9 percent) have been submitted by EKPC or one of their affiliated companies.

Table 12-36 Relationship between project developer and transmission owner for all combined cycle project MW in PJM interconnection queue: December 31, 2018

			MW by Project Status					
Parent Company	Transmission Owner	Related to Developer	Active	In Service	Under Construction	Suspended	Withdrawn	Total
AEP	AEP	Related	100.0	580.0	0.0	0.0	0.0	680.0
		Unrelated	7,231.0	2,682.0	100.0	585.0	11,960.5	22,558.5
AES	DAY	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	1,150.0	0.0	0.0	0.0	0.0	1,150.0
DLCO	DLCO	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	0.0	0.0	0.0	0.0	665.0	665.0
Dominion	Dominion	Related	0.0	3,092.0	1,681.0	0.0	7,501.0	12,274.0
		Unrelated	2,770.0	1,934.1	0.0	0.0	4,340.4	9,044.5
Duke	DEOK	Related	0.0	0.0	0.0	0.0	36.0	36.0
		Unrelated	0.0	533.0	0.0	0.0	134.5	667.5
EKPC	EKPC	Related	0.0	0.0	0.0	0.0	821.8	821.8
		Unrelated	0.0	0.0	0.0	0.0	170.0	170.0
Exelon	AECO	Related	0.0	0.0	0.0	0.0	730.0	730.0
		Unrelated	996.6	870.0	452.0	0.0	6,529.8	8,848.4
	BGE	Related	0.0	130.0	0.0	0.0	120.0	250.0
		Unrelated	0.0	10.0	0.0	0.0	3,002.1	3,012.1
	ComEd	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	6,696.6	1,221.0	12.6	0.0	7,600.3	15,530.5
	DPL	Related	0.0	60.0	0.0	0.0	1,305.0	1,365.0
		Unrelated	0.0	361.2	0.0	451.0	4,799.4	5,611.6
	PECO	Related	0.0	0.0	0.0	0.0	6,965.0	6,965.0
		Unrelated	67.0	2,758.5	915.0	0.0	16,615.0	20,355.5
	Pepco	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	75.0	1,629.6	84.0	1,038.1	20,499.2	23,325.9
First Energy	APS	Related	0.0	525.0	0.0	0.0	928.0	1,453.0
		Unrelated	5,505.7	670.0	930.0	1,160.0	16,633.1	24,898.8
	ATSI	Related	0.0	0.0	0.0	0.0	1,678.0	1,678.0
		Unrelated	5,805.0	1,905.0	0.0	0.0	5,879.0	13,589.0
	JCPL	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	715.0	1,775.8	0.0	460.0	12,805.6	15,756.4
	Met-Ed	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	113.9	2,117.0	485.0	0.0	14,743.0	17,458.9
	PENELEC	Related	0.0	0.0	0.0	0.0	534.0	534.0
		Unrelated	85.0	942.3	1,100.0	163.0	16,437.6	18,727.9
OVEC	OVEC	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	0.0	0.0	0.0	0.0	0.0	0.0
PPL	PPL	Related	0.0	600.0	0.0	0.0	1,661.0	2,261.0
		Unrelated	1,722.8	5,379.0	483.0	0.0	15,624.7	23,209.5
PSEG	PSEG	Related	51.1	1,920.0	568.0	0.0	9,297.0	11,836.1
		Unrelated	3,091.4	806.4	0.0	0.0	15,417.6	19,315.4
Con Ed	RECO	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	0.0	0.0	0.0	0.0	6.9	6.9
Total		Related	151.1	6,907.0	2,249.0	0.0	31,576.8	40,883.9
		Unrelated	36,025.0	25,594.8	4,561.6	3,857.1	173,863.5	243,902.1

Combustion Turbine – Natural Gas Project Developer and Transmission Owner Relationships

Table 12-37 shows the relationship between the project developer and Transmission Owner for all CT – natural gas project MW that have entered the PJM generation queue from January 1, 1997 through December 31, 2018, by transmission owner and project status. Of the 9,177.0 CT – natural gas project MW that have achieved in service or under construction status during this time period, 2,107.0 (23.0 percent) have been developed by Transmission Owners building in their own service territory. PSEG is the Transmission Owner with the highest percentage of affiliates building CT – natural gas projects in their own service territory. Of the 2,281.0 MW that entered the queue during the time period of January 1, 1997, through December 31, 2018, 1,818.1 MW (79.7 percent) have been submitted by PSEG or one of their affiliated companies.

Table 12-37 Relationship between project developer and transmission owner for all CT – natural gas project MW in PJM interconnection queue: December 31, 2018

			MW by Project Status					
Parent Company	Transmission Owner	Related to Developer	Active	In Service	Under Construction	Suspended	Withdrawn	Total
AEP	AEP	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	1,491.0	190.0	0.0	0.0	72.0	1,753.0
AES	DAY	Related	0.0	38.0	0.0	0.0	0.0	38.0
		Unrelated	0.0	22.0	0.0	0.0	0.0	22.0
DLCO	DLCO	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	0.0	0.0	205.0	0.0	0.0	205.0
Dominion	Dominion	Related	122.7	786.0	0.0	0.0	0.0	908.7
		Unrelated	1,033.6	1,116.7	0.0	0.0	75.5	2,225.8
Duke	DEOK	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	0.0	0.0	0.0	0.0	0.0	0.0
EKPC	EKPC	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	73.0	0.0	0.0	0.0	0.0	73.0
Exelon	AECO	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	388.0	404.4	0.0	0.0	15.0	807.4
	BGE	Related	0.0	10.0	0.0	0.0	0.0	10.0
		Unrelated	153.6	13.0	0.0	0.0	0.0	166.6
	ComEd	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	1,190.0	257.0	48.0	0.0	10.0	1,505.0
	DPL	Related	0.0	351.0	0.0	0.0	0.0	351.0
		Unrelated	0.0	1,226.0	0.0	0.0	0.0	1,226.0
	PECO	Related	0.0	5.0	0.0	0.0	0.0	5.0
		Unrelated	29.0	567.0	0.0	0.0	0.5	596.5
	Pepco	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	0.0	37.0	0.0	0.0	0.0	37.0
First Energy	APS	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	120.0	1,363.7	0.0	0.0	0.0	1,483.7
	ATSI	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	70.0	40.0	0.0	0.0	25.0	135.0
	JCPL	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	0.0	522.1	0.0	200.0	0.0	722.1
	Met-Ed	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	0.0	44.1	0.0	0.0	0.0	44.1
	PENELEC	Related	0.0	5.0	0.0	0.0	0.0	5.0
		Unrelated	481.0	381.9	0.0	68.8	493.0	1,424.7
OVEC	OVEC	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	0.0	0.0	0.0	0.0	0.0	0.0
PPL	PPL	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	0.0	403.2	0.0	0.0	19.9	423.1
PSEG	PSEG	Related	0.0	912.0	0.0	0.0	906.1	1,818.1
		Unrelated	0.0	228.9	0.0	0.0	234.0	462.9
Con Ed	RECO	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	0.0	0.0	0.0	0.0	0.0	0.0
Total		Related	122.7	2,107.0	0.0	0.0	906.1	3,135.8
		Unrelated	5,029.2	6,817.0	253.0	268.8	944.9	13,312.9

Wind Project Developer and Transmission Owner Relationships

Table 12-38 shows the relationship between the project developer and Transmission Owner for all wind project MW that have entered the PJM generation queue from January 1, 1997 through December 31, 2018, by transmission owner and project status. Of the 9,879.0 wind project MW that have achieved in service or under construction status during this time period, 12.0 MW (0.1 percent) have been developed by Transmission Owners building in their own service territory. Dominion is the Transmission Owner with the highest percentage of affiliates building wind projects in their own service territory. Of the 5,893.8 MW that entered the queue during the time period of January 1, 1997, through December 31, 2018, 146.0 MW (2.5 percent) have been submitted by Dominion or one of their affiliated companies.

Table 12-38 Relationship between project developer and transmission owner for all wind project MW in PJM interconnection queue: December 31, 2018

			MW by Project Status					
Parent Company	Transmission Owner	Related to Developer	Active	In Service	Under Construction	Suspended	Withdrawn	Total
AEP	AEP	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	5,617.3	2,538.7	350.0	722.0	19,653.2	28,881.2
AES	DAY	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	100.0	0.0	0.0	0.0	2,028.0	2,128.0
DLCO	DLCO	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	0.0	0.0	0.0	0.0	0.0	0.0
Dominion	Dominion	Related	0.0	0.0	12.0	0.0	134.0	146.0
		Unrelated	2,400.3	102.5	632.3	76.6	2,536.1	5,747.8
Duke	DEOK	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	0.0	0.0	0.0	0.0	0.0	0.0
EKPC	EKPC	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	0.0	0.0	0.0	0.0	150.3	150.3
Exelon	AECO	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	521.0	7.5	0.0	0.0	3,626.4	4,154.9
	BGE	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	0.0	0.0	0.0	0.0	0.0	0.0
	ComEd	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	8,368.7	2,688.0	954.0	0.0	22,527.3	34,538.0
	DPL	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	599.8	0.0	0.0	0.0	2,816.8	3,416.6
	PECO	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	0.0	0.0	0.0	0.0	0.0	0.0
	Pepco	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	0.0	0.0	0.0	0.0	0.0	0.0
First Energy	APS	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	444.4	1,004.0	298.0	360.0	3,234.1	5,340.5
	ATSI	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	816.1	0.0	0.0	0.0	1,295.6	2,111.7
	JCPL	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	3,016.0	0.0	0.0	0.0	0.0	3,016.0
	Met-Ed	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	0.0	0.0	0.0	0.0	0.0	0.0
	PENELEC	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	120.3	995.5	70.0	100.0	5,520.3	6,806.2
OVEC	OVEC	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	0.0	0.0	0.0	0.0	0.0	0.0
PPL	PPL	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	257.3	226.5	0.0	98.0	3,248.1	3,829.9
PSEG	PSEG	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	0.0	0.0	0.0	0.0	20.0	20.0
Con Ed	RECO	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	0.0	0.0	0.0	0.0	0.0	0.0
Total		Related	0.0	0.0	12.0	0.0	134.0	146.0
		Unrelated	22,261.1	7,562.7	2,304.3	1,356.6	66,656.2	100,140.9

Solar Project Developer and Transmission Owner Relationships

Table 12-39 shows the relationship between the project developer and Transmission Owner for all solar project MW that have entered the PJM generation queue from January 1, 1997 through December 31, 2018, by transmission owner and project status. Of the 1,776.4 solar project MW that have achieved in service or under construction status during this time period, 475.6 MW (26.8 percent) have been developed by Transmission Owners building in their own service territory. BGE is the Transmission Owner with the highest percentage of affiliates building solar projects in their own service territory. Of the 54.4 MW that entered the queue during the time period of January 1, 1997, through December 31, 2018, 20.0 MW (36.8 percent) have been submitted by BGE or one of their affiliated companies.

Table 12-39 Relationship between project developer and transmission owner for all solar project MW in PJM interconnection queue: December 31, 2018

			MW by Project Status					
Parent Company	Transmission Owner	Related to Developer	Active	In Service	Under Construction	Suspended	Withdrawn	Total
AEP	AEP	Related	68.0	14.7	0.0	10.0	50.0	142.7
		Unrelated	7,668.9	0.0	0.0	30.0	6,526.6	14,225.6
AES	DAY	Related	0.0	0.0	0.0	0.0	21.5	21.5
		Unrelated	1,116.5	2.5	0.0	20.0	502.4	1,641.4
DLCO	DLCO	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	20.0	0.0	0.0	0.0	0.0	20.0
Dominion	Dominion	Related	340.3	309.4	20.0	0.0	231.9	901.6
		Unrelated	14,193.9	329.8	188.8	5.0	8,981.1	23,698.6
Duke	DEOK	Related	0.0	0.0	0.0	0.0	6.4	6.4
		Unrelated	380.0	0.0	0.0	0.0	273.0	653.0
EKPC	EKPC	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	986.0	0.0	0.0	0.0	189.9	1,175.9
Exelon	AECO	Related	0.0	0.0	0.0	0.0	8.3	8.3
		Unrelated	311.5	57.3	0.0	0.0	1,667.0	2,035.8
	BGE	Related	0.0	0.0	0.0	0.0	20.0	20.0
		Unrelated	0.0	1.1	0.0	0.0	33.3	34.4
	ComEd	Related	0.0	9.0	0.0	0.0	0.0	9.0
		Unrelated	2,618.5	0.0	0.0	0.0	1,836.8	4,455.3
	DPL	Related	0.0	7.4	0.0	0.0	0.0	7.4
		Unrelated	1,405.2	111.0	37.0	0.0	1,540.7	3,093.9
	PECO	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	18.0	3.3	0.0	0.0	51.4	72.7
	Pepco	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	176.5	0.0	0.0	0.0	128.1	304.6
First Energy	APS	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	1,037.4	53.0	10.0	313.3	1,486.4	2,900.1
	ATSI	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	999.1	0.0	0.0	0.0	271.1	1,270.2
	JCPL	Related	0.0	0.0	0.0	0.0	12.0	12.0
		Unrelated	68.2	311.6	71.9	37.6	1,360.6	1,849.8
	Met-Ed	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	541.6	0.0	0.0	3.0	467.0	1,011.6
	PENELEC	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	458.8	0.0	0.0	0.0	171.7	630.5
OVEC	OVEC	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	0.0	0.0	0.0	0.0	0.0	0.0
PPL	PPL	Related	19.8	0.0	0.0	0.0	0.0	19.8
		Unrelated	154.8	15.0	0.0	0.0	383.7	553.5
PSEG	PSEG	Related	24.3	111.1	4.0	0.0	36.4	175.8
		Unrelated	31.9	82.4	26.1	6.0	441.7	588.0
Con Ed	RECO	Related	0.0	0.0	0.0	0.0	0.0	0.0
		Unrelated	60.0	0.0	0.0	0.0	0.0	60.0
Total		Related	452.4	451.6	24.0	10.0	386.5	1,324.4
		Unrelated	32,246.6	967.0	333.8	414.9	26,312.5	60,274.9

Regional Transmission Expansion Plan (RTEP)[38]

The PJM RTEP process is designed to identify needed transmission system additions and improvements to continue to provide reliable service throughout the RTO. The objective of the RTEP process is to provide PJM with an optimal set of solutions necessary to solve reliability issues, operational performance issues and transmission constraints.

The RTEP process initially considered only factors such as load growth and the generation interconnection requests in its development of the 15 year plan. Currently, the RTEP process includes a broader range of inputs including the effects of public policy, market efficiency, interregional coordination and the effects of aging infrastructure.

RTEP Process

The PJM RTEP process is a 24 month planning process that identifies reliability issues for the next 15 year period. This 24 month planning process includes a process to build power flow models that represent the expected future system topology, studies to identify issues, stakeholder input and PJM Board of Manager approvals. The 24 month planning process is made up of overlapping 18 month planning cycles to identify and develop shorter lead time transmission upgrades and one 24 month planning cycle to provide sufficient time for the identification and development of longer lead time transmission upgrades that may be required to satisfy planning criteria.

Backbone Facilities

PJM baseline transmission projects are implemented to resolve reliability criteria violations. PJM backbone transmission projects are a subset of significant baseline projects, which are intended to resolve multiple reliability criteria violations and congestion issues and which may have substantial impacts on energy and capacity markets. There are currently three backbone projects under development, Surry Skiffes Creek 500kV, and the conversion of the Marion-Bayonne and Bayway-Linden lines from 138 kV to 345 kV.[39]

Market Efficiency Process

PJM's Regional Transmission Expansion Plan (RTEP) process includes a market efficiency analysis. The stated purpose of the market efficiency analysis is: to determine which reliability based enhancements have economic benefit if accelerated; to identify new transmission enhancements that result in economic benefits; and to identify economic benefits associated with modification to existing RTEP reliability based enhancements that when modified would relieve one or more economic constraints. PJM identifies the economic benefit of proposed transmission projects based on production cost analyses.[40] PJM presents the RTEP market efficiency enhancements to the PJM Board, along with stakeholder input, for Board approval.

To be recommended to the PJM Board of Managers for approval, the relative benefits and costs of the economic based enhancement or expansion must meet a benefit/cost ratio threshold of at least 1.25:1. The benefit/cost ratio is the ratio of the present value of the total annual benefit for 15 years to the present value of the total annual cost for the first 15 years of the life of the enhancement or expansion.

The market efficiency process is comprised of a 12 month cycle and a 24 month cycle, both of which begin and end on the calendar year. The 12 month cycle is used for analysis of modifications and accelerations to approved RTEP projects only. The 24 month cycle is used for analysis of new economic transmission projects for years five through 15. This long-term proposal window takes place concurrent with the long-term proposal window for reliability projects.[41]

PJM's first market efficiency analysis was performed in 2013, prior to Order 1000. That analysis evaluated the historical sources of congestion on 25 flowgates.[42]

38 The material in this section is based in part on the PJM Manual 14B: PJM Region Transmission Planning Process. See PJM. "*PJM Manual 14B: PJM Region Transmission Planning Process*," Rev. 42 (Aug. 23, 2018) <http://www.pjm.com/-/media/documents/manuals/m14b.ashx?la=en>.

39 See PJM, "*2017 RTEP Process Scope and Input Assumptions White Paper*," at 25. <http://www.pjm.com/-/media/library/reports-notices/2017-rtep/20170731-rtep-input-assumptions-and-scope-whitepaper.ashx?la=en>.

40 See PJM, "*PJM Regional Transmission Expansion Plan: 2016*" (February 28, 2017). <http://www.pjm.com/-/media/library/reports-notices/2016-rtep/2016-rtep-books-1-3.ashx?la=en>.

41 See PJM, "*PJM Market Efficiency Modeling Practices*" (February 2, 2017). <http://www.pjm.com/-/media/planning/rtep-dev/market-efficiency/pjm-market-efficiency-modeling-practices.ashx?la=en>.

42 Historical congestion drivers are identified using the historical congestion tables presented in the *State of the Market Report for PJM*, Section 11: Congestion and Marginal Losses, historical analysis of real time constraints, the NERC Book of Flowgates and PROMOD simulations.

The proposal window was open from August 12, 2013, through September 26, 2013. PJM received 38 proposals from six entities. One project was approved by the PJM Board.

The first market efficiency cycle conducted under Order 1000 was performed during the 2014/2015 RTEP long term window. That analysis evaluated the historical sources of congestion on 77 flowgates, 57 of which could be addressed by market efficiency projects. The proposal window was open from October 30, 2014, through February 27, 2015. PJM received 119 proposals, 93 of which addressed the market efficiency issues, with the remaining submissions addressing reliability issues identified by PJM. A total of 14 projects were approved by the PJM Board for this window, 13 of which were market efficiency projects and one of which was for reliability.

The second market efficiency cycle was performed during the 2016/2017 RTEP long term window. That analysis evaluated the historical sources of congestion on a total of four flowgates, all four of which could be addressed by market efficiency projects. The proposal window was open from November 1, 2016, through February 28, 2017. PJM received 96 proposals, all 96 of which addressed market efficiency issues. A total of four projects were approved by the PJM Board for this window, all four of which were market efficiency projects.

The third market efficiency cycle is currently being prepared for the 2018/2019 RTEP long term window. The proposal window will be open from November 1, 2018 through February 28, 2019.

In 2018, the PJM Board of Managers received correspondence from several officials, representing regions in Pennsylvania and Maryland, requesting an updated benefit/cost evaluation and the cancellation of the previously approved Transource AP-South market efficiency project.[43] [44] [45] [46] Approved market efficiency projects periodically undergo a reevaluation process to ensure that the benefit/cost ratio continues to meet the 1.25:1 threshold. The Transource AP-South project was reevaluated in September 2017, February 2018 and again in September 2018. The project exceeded the 1.25:1 threshold in all reevaluations. PJM also concluded that there would be significant reliability violations with the project removed from the model.[47]

The Benefit/Cost Evaluation

For an RTEP project to be recommended to the PJM Board of Managers for approval as a Market Efficiency project, the relative benefits and costs of the economic based enhancement or expansion must meet a benefit/cost ratio threshold of at least 1.25:1.

The total benefit of a project is calculated as the sum of the net present value of calculated energy market benefits and calculated reliability pricing model (RPM) benefits for a 15 year period, starting with the projected in service date of the project. Benefits are reductions in estimated load charges and production costs in the energy market and reductions in estimated load capacity payments and in system capacity costs in the capacity market. The method for calculating energy market benefits and reliability pricing model benefits used to measure the benefit of an RTEP project for purposes of the 1.25:1 benefit/cost ratio threshold depends on whether the project is regional or subregional. A regional project is any project rated at or above 230 kV. A subregional project is any project rated at less than 230 kv. For a regional project, the benefit for each modeled year is equal to 50 percent of the change in system energy production costs and generation capacity payments with and without the project plus 50 percent of the change in zonal load energy payments and 50 percent of zonal load capacity payments with and without the project,

43 See Letter from Governor Larry Hogan, State of Maryland, Office of the Governor (July 10, 2018) <https://www.pjm.com/-/media/about-pjm/who-we-are/public-disclosures/20180828-gov-hogan-transource-july-2018-letter-to-pjm-board.ashx?la=en>.

44 See Letter from State Representative Kristin Phillips Hill, 93rd District, Pennsylvania House of Representatives (September 6, 2018) <https://www.pjm.com/-/media/about-pjm/who-we-are/public-disclosures/20180906-pa-rep-phillips-hill-letter-re-transource-llc.ashx?la=en>.

45 See Letter from State Representative Stanley E. Saylor, 94th District, Pennsylvania House of Representatives (August 1, 2018) <https://www.pjm.com/-/media/about-pjm/who-we-are/public-disclosures/20180907-pa-rep-saylor-letter-re-transource-llc.ashx?la=en>.

46 See Letter from Paula M. Carmody, People Counsel, State of Maryland Office of People's Counsel (September 6, 2018) <https://www.pjm.com/-/media/about-pjm/who-we-are/public-disclosures/20180907-opc-letter-to-pjm-board-re-sept-2018-transource-retool.ashx?la=en>.

47 See "Transource AP-South (2014/15_9A) Project Reevaluation," <https://www.pjm.com/-/media/committees-groups/committees/teac/20180913/20180913-ap-south-9a-project-reevaluation-sept-2018.ashx>.

including only those zones where the project reduced the load energy payments and reduced the load capacity payments. For subregional projects, the benefits for each modeled year are equal to the change in zonal energy and capacity payments with and without the project, including only those zones where the project reduced the energy and capacity payments.

The Energy Market Benefit analysis uses an energy market simulation tool that produces an hourly least-cost, security constrained market solution, including total operational costs, hourly LMPs, bus specific injections and bus specific withdrawals for each modeled year with and without the proposed RTEP project. Using the output from the model, PJM calculates changes in Energy Production Costs and Load Energy Payments. Energy Production Costs are the sum of generation payments in the energy market simulation in each modeled year. The change in the Energy Production costs in each modeled year is calculated on a system wide basis Using the modeled changes in LMPs, changes in Load Energy Payments are calculated on a zonal basis and are netted against corresponding changes in the estimated value of any Auction Revenue Rights (ARR) that sink in that zone. Estimated ARR credits are calculated for each simulated year using the most recent planning year's actual ARR MW combined with FTR prices assumed to be equal to the market simulation's CLMP differences between ARR source and sink points. The value of the ARR rights with and without the RTEP project is evaluated based on changes in modeled CLMPs on the latest, historic allocation of ARR rights. ARR MW allocations are not adjusted to reflect any potential changes in ARR allocations which may be allowed by the RTEP upgrade.

The Reliability Pricing Model Benefit analysis is conducted using the Reliability Pricing Model solution software, with and without the proposed RTEP project, using a set of estimated capacity offers.

The definition of the benefit in the RPM benefit analysis depends on whether the project is regional or subregional. For a regional project, the RPM benefit for each modeled year is equal to 50 percent of the change in system-wide Total System Capacity Cost with and without the project plus 50 percent of the change in zonal Load Capacity Payments with and without the project, including only those zones where the project reduced the Load Capacity Payments. For subregional projects, the reliability pricing model benefits for each modeled year is equal to the change in zonal Load Capacity Payments with and without the project, including only those zones where the project reduced the Load Capacity Payments.

The difference in the benefits calculation used in the regional and subregional cost benefit threshold tests are related to how costs are allocated for approved regional and subregional projects. The costs of an approved regional project are allocated so that 50 percent of the total costs are allocated on a system wide load ratio share basis and the remaining 50 percent of the total costs are allocated to zones with projected energy market benefits and reliability pricing model benefits in proportion to those projected positive benefits. The costs of an approved subregional project are allocated so that the total costs of the project is allocated to zones with projected energy market benefits and reliability pricing model benefits in proportion to those projected positive benefits.

The current rules governing benefit/cost analysis of competing transmission projects do not correctly measure the relative costs and benefits of transmission projects. The current rules explicitly ignore the increased congestion costs that an RTEP project may create in a subset of zones when calculating the energy market benefits. The current rules do not account for the risk associated with the fact that the project costs are nonbinding estimates. All costs should be included in all zones and LDAs.

PJM MISO Interregional Targeted Market Efficiency Process (TMEP)

PJM and MISO developed a process to facilitate the construction of interregional projects in response to the Commissions concerns about interregional coordination along the PJM-MISO seam, called the Targeted Market Efficiency Process (TMEP).[48]

The allocation of costs to each RTO for TMEPs will be in proportion to the benefits received.[49]

On November 2, 2017, PJM submitted a compliance filing including additional revisions the MISO-PJM JOA

48 See *PJM Interconnection, L.L.C*, Docket No. ER17-718-000 (December 30, 2016).
49 See *PJM Interconnection, L.L.C*, Docket No. ER17-729-000 (December 30, 2016).

to include stakeholder feedback in the TMEP project selection process.[50] [51]

The first TMEP analysis occurred in 2017 and included the investigation of congestion on 50 market to market flowgates. The study resulted in the evaluation of 13 potential upgrades, resulting in the recommendation of five TMEP projects. The five projects address $59 million in historical congestion, with a TMEP benefit of $99.6 million. The projects have a total cost of $20 million, with a 5.0 average benefit/cost ratio. PJM and MISO presented the five recommended projects to their boards in December, 2017, and both boards approved all five projects.[52]

The 2018 TMEP analysis included the investigation of congestion on 61 market to market flowgates. The study resulted in the evaluation of 19 potential upgrades, resulting in the recommendation of two TMEP projects. The two projects address $25 million in historical congestion, with a TMEP benefit of $31.9 million. The projects have a total cost of $4.5 million, with a 7.1 average benefit/cost ratio. PJM and MISO presented the two recommended projects to their boards in December, 2018, and both boards approved the projects.[53]

Supplemental Transmission Projects

Supplemental projects are "transmission expansions or enhancements that are not required for compliance with PJM criteria and are not state public policy projects according to the PJM Operating Agreement. These projects are used as inputs to RTEP models, but are not required for reliability, economic efficiency or operational performance criteria, as determined by PJM."[54] Supplemental projects are selected solely by the Transmission Owner and no PJM approval is needed. Supplemental projects are currently exempt from the Order No. 1000 competitive process. Transmission owners have a clear incentive to increase investments in rate base given that transmission owners are paid for these projects on a cost of service basis.

Figure 12-3 shows the latest cost estimate of all supplemental projects by expected in service year. FERC Order 890 was issued on February 16, 2007, and implemented in PJM starting in 2008. Order 890 required Transmission Providers to participate in a coordinated, open and transparent planning process. Prior to the implementation of Order 890, there were transmission projects planned by transmission owners and included in the PJM planning models, that were not included in the totals shown in Figure 12-3, Table 12-40 and Table 12-41. There has been a significant increase in supplemental projects coincident with the coordinated, open and transparent planning process introduced by the implementation of Order 890 starting in 2008 and the competitive planning process introduced by the implementation of FERC Order No. 1000 starting in 2011.

Figure 12-3 Latest cost estimate of supplemental projects by expected in service year: 1998 through 2018

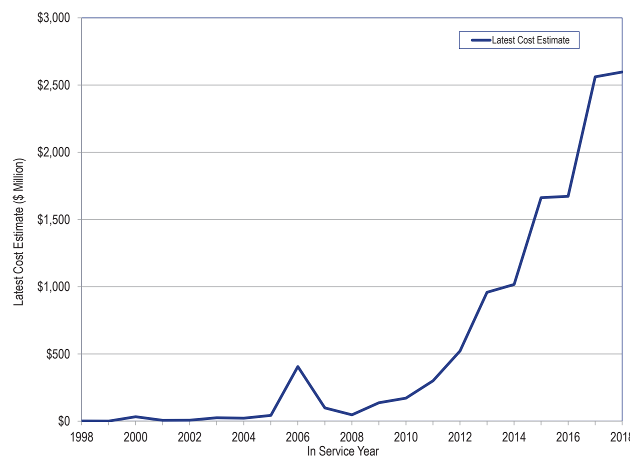


Table 12-40 shows the number of supplemental projects by expected in service year for each transmission zone. The average number of supplemental projects in each expected in service year increased by 520.0 percent, from 20 for years 1998 through 2007 (pre Order 890) to 124 for years 2008 through 2018 (post Order 890).

50 See *PJM Interconnection, L.L.C*, Docket No. ER17-718-000, ER17-721-000 and ER17-729-000 (Not Consolidated) (November 2, 2017).

51 161 FERC ¶ 61,005.

52 See PJM, "*MISO PJM IPSAC*," (January 12, 2018) <http://www.pjm.com/-/media/committees-groups/stakeholder-meetings/ipsac/20180112/20180112-ipsac-presentation.ashx>.

53 See PJM. "*MISO PJM IPSAC*," (January 18, 2019) <https://www.pjm.com/-/media/committees-groups/stakeholder-meetings/ipsac/20190118/20190118-ipsac-presentation.ashx>.

54 See PJM, "*Transmission Construction Status*," (January 23, 2018) <http://www.pjm.com/planning/rtep-upgrades-status/construct-status.aspx>.

Table 12-40 Number of supplemental projects by expected in service year and zone: 1998 through 2040

Year	AECO	AEP	APS	ATSI	BGE	ComEd	DAY	DEOK	DLCO	Dominion	DPL	EKPC	JCPL	Met-Ed	OVEC	PECO	PENELEC	Pepco	PPL	PSEG	RECO	Total
1998	0	0	0	0	0	0	0	0	0	0	3	0	0	0	0	0	0	0	0	0	0	3
1999	0	0	0	0	0	0	0	0	0	0	2	0	0	0	0	0	0	0	0	0	0	2
2000	0	0	0	0	0	0	0	0	0	0	11	0	0	0	0	0	0	0	0	0	0	11
2001	0	0	0	0	0	0	0	0	0	0	14	0	0	0	0	0	0	0	0	0	0	14
2002	0	0	0	0	0	0	0	0	0	0	10	0	0	0	0	0	0	0	0	0	0	10
2003	3	0	0	0	0	0	0	0	0	0	10	0	0	0	0	0	2	0	0	0	0	15
2004	5	0	10	0	0	9	0	0	0	0	12	0	2	0	0	0	0	0	0	2	0	40
2005	4	2	8	0	0	4	0	0	0	1	14	0	1	0	0	1	2	0	0	2	0	39
2006	4	2	5	0	0	6	0	0	0	0	9	0	1	0	0	0	1	0	2	1	0	31
2007	1	1	5	0	4	5	0	0	4	0	6	0	0	0	0	0	2	0	1	6	0	35
2008	3	0	15	0	1	6	0	0	1	7	3	0	0	1	0	0	0	0	3	1	0	41
2009	3	1	6	0	1	8	0	0	3	3	5	0	0	0	0	5	1	0	0	2	0	38
2010	0	6	7	0	3	4	0	0	6	3	0	0	1	2	0	2	0	0	2	5	0	41
2011	0	8	8	0	0	2	0	0	5	2	0	0	1	0	0	4	0	0	3	4	0	37
2012	0	5	6	4	1	2	0	7	3	16	1	0	2	0	0	1	0	0	4	11	0	63
2013	5	21	4	5	0	11	0	6	5	13	1	0	1	1	0	1	0	1	13	19	0	107
2014	2	31	2	8	2	14	0	5	6	18	3	2	2	0	0	1	2	0	9	16	0	123
2015	4	15	2	9	1	37	0	8	4	17	5	4	2	0	0	1	0	4	7	24	0	144
2016	5	13	4	17	0	26	0	6	2	13	4	2	0	1	0	3	2	3	11	30	0	142
2017	8	103	3	26	1	23	0	3	8	35	11	5	0	3	0	0	3	1	21	43	0	297
2018	10	156	4	15	6	26	0	19	7	28	6	4	0	1	0	2	4	1	14	30	0	333
2019	8	180	2	23	1	12	2	18	2	13	8	9	0	0	0	1	13	1	33	25	0	351
2020	9	117	0	15	2	2	0	5	1	11	5	3	0	5	0	0	4	0	19	22	0	220
2021	6	62	0	5	0	2	10	0	1	8	2	2	1	2	0	0	0	0	22	26	1	150
2022	4	5	0	0	2	0	0	1	0	0	4	0	1	0	0	0	0	2	21	16	0	56
2023	2	4	0	0	0	0	0	0	2	1	2	0	1	3	0	0	1	0	12	0	0	28
2024	1	0	1	0	7	0	0	0	0	0	0	0	0	0	0	0	0	0	12	0	0	21
2025	1	0	0	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	6	0	0	8
2026	0	0	0	0	4	0	0	0	0	0	0	0	0	0	0	0	0	0	13	0	0	17
2027	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1	0	0	1
2028	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2029	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2030	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	4	0	0	4
2031	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2032	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2033	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2034	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2035	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2036	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2037	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2038	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2039	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2040	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	4	0	0	4
Total	88	732	92	127	37	199	12	78	60	189	151	31	16	19	0	22	37	13	237	285	1	2,426

Table 12-41 shows the latest cost estimate of supplemental projects by expected in service year for each transmission zone. The average latest cost of supplemental projects in each expected in service year increased by 1,541.6 percent, from $64.5 million for years 1998 through 2007 (pre Order 890) to $1,058.8 million for years 2008 through 2018 (post Order 890).

Table 12-41 Latest cost estimate by expected in service year and zone ($ millions): 1998 through 2040

Year	AECO	AEP	APS	ATSI	BGE	ComEd	DAY	DEOK	DLCO	Dominion	DPL	EKPC	JCPL	Met-Ed	OVEC	PECO	PENELEC	Pepco	PPL	PSEG	RECO	Total
1998	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$1.67	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$1.67
1999	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.78	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.78
2000	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$32.95	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$32.95
2001	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$6.79	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$6.79
2002	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$7.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$7.00
2003	$7.42	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$8.75	$0.00	$0.00	$0.00	$0.00	$0.00	$9.60	$0.00	$0.00	$0.00	$0.00	$25.77
2004	$4.44	$0.00	$9.99	$0.00	$0.00	$0.82	$0.00	$0.00	$0.00	$0.00	$7.32	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$22.58
2005	$4.06	$14.67	$10.11	$0.00	$0.00	$2.58	$0.00	$0.00	$0.00	$0.02	$10.97	$0.00	$0.00	$0.00	$0.00	$0.50	$0.00	$0.00	$0.00	$0.00	$0.00	$42.90
2006	$4.03	$309.70	$0.94	$0.00	$0.00	$48.93	$0.00	$0.00	$0.00	$0.00	$11.63	$0.00	$6.00	$0.00	$0.00	$0.00	$1.50	$0.00	$4.63	$18.80	$0.00	$406.15
2007	$0.56	$2.06	$9.85	$0.00	$37.61	$4.65	$0.00	$0.00	$31.75	$0.00	$9.71	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.34	$2.25	$0.00	$98.77
2008	$2.36	$0.00	$12.03	$0.00	$0.45	$7.61	$0.00	$0.00	$7.00	$14.01	$2.28	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$1.60	$0.00	$0.00	$47.33
2009	$0.77	$0.90	$12.22	$0.00	$5.00	$21.11	$0.00	$0.00	$19.60	$2.12	$7.36	$0.00	$0.00	$0.00	$0.00	$48.10	$2.73	$0.00	$0.00	$17.60	$0.00	$137.51
2010	$0.00	$34.36	$12.13	$0.00	$18.90	$1.38	$0.00	$0.00	$34.45	$14.98	$0.00	$0.00	$0.03	$4.58	$0.00	$31.80	$0.00	$0.00	$1.08	$17.72	$0.00	$171.41
2011	$0.00	$37.60	$9.30	$0.00	$0.00	$1.00	$0.00	$0.00	$16.72	$85.67	$0.00	$0.00	$1.16	$0.00	$0.00	$113.30	$0.00	$0.00	$0.78	$34.60	$0.00	$300.13
2012	$0.00	$46.00	$5.12	$0.35	$2.20	$12.60	$0.00	$26.06	$11.60	$165.74	$0.99	$0.00	$6.61	$0.00	$0.00	$12.60	$0.00	$0.00	$8.91	$223.01	$0.00	$521.79
2013	$3.15	$134.93	$1.10	$33.68	$0.00	$59.25	$0.00	$9.93	$81.98	$25.03	$0.99	$0.00	$0.05	$4.10	$0.00	$22.50	$0.00	$2.40	$75.84	$503.72	$0.00	$958.65
2014	$8.03	$387.00	$5.97	$58.70	$21.20	$60.37	$0.00	$2.43	$14.90	$88.61	$5.96	$0.38	$5.60	$0.00	$0.00	$13.30	$1.30	$0.00	$33.47	$309.70	$0.00	$1,016.92
2015	$3.73	$237.45	$3.80	$21.90	$2.00	$376.00	$0.00	$14.12	$4.53	$113.53	$13.06	$1.56	$0.30	$0.00	$0.00	$33.80	$0.00	$42.50	$50.17	$743.91	$0.00	$1,662.36
2016	$73.54	$79.98	$18.40	$182.70	$0.00	$308.15	$0.00	$15.13	$26.95	$40.68	$26.60	$0.25	$0.00	$2.37	$0.00	$86.40	$0.40	$7.80	$58.76	$744.18	$0.00	$1,672.29
2017	$66.28	$642.74	$8.60	$142.05	$0.09	$145.97	$0.00	$65.01	$3.62	$106.14	$92.29	$2.21	$0.00	$14.70	$0.00	$0.00	$8.30	$12.00	$261.74	$988.92	$0.00	$2,560.66
2018	$71.73	$773.84	$14.80	$61.58	$7.89	$140.03	$0.00	$121.80	$9.74	$182.27	$79.79	$10.87	$0.00	$2.40	$0.00	$47.60	$15.10	$156.00	$184.90	$716.93	$0.00	$2,597.27
2019	$86.45	$1,325.37	$0.93	$177.80	$67.20	$95.20	$7.81	$74.39	$10.90	$35.60	$46.26	$33.49	$0.00	$0.00	$0.00	$0.80	$77.10	$70.00	$414.24	$703.56	$0.00	$3,227.10
2020	$78.54	$969.72	$0.00	$154.90	$62.50	$49.00	$0.00	$42.41	$16.80	$27.43	$34.22	$15.46	$0.00	$36.60	$0.00	$0.00	$76.70	$0.00	$314.90	$1,977.08	$0.00	$3,856.26
2021	$33.46	$1,011.31	$0.00	$138.80	$0.00	$2.00	$57.10	$0.00	$20.00	$77.40	$16.11	$14.70	$16.00	$40.10	$0.00	$0.00	$0.00	$0.00	$290.80	$935.15	$17.00	$2,669.93
2022	$106.40	$87.60	$0.00	$0.00	$263.00	$0.00	$0.00	$0.12	$0.00	$0.00	$35.00	$0.00	$22.00	$0.00	$0.00	$0.00	$0.00	$527.00	$432.30	$970.00	$0.00	$2,443.42
2023	$12.84	$54.70	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$40.00	$32.00	$29.72	$0.00	$8.50	$16.30	$0.00	$0.00	$200.00	$0.00	$148.90	$0.00	$0.00	$542.96
2024	$0.00	$0.00	$3.60	$0.00	$223.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$272.43	$0.00	$0.00	$499.03
2025	$64.00	$0.00	$0.00	$0.00	$7.50	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$143.00	$0.00	$0.00	$214.50
2026	$0.00	$0.00	$0.00	$0.00	$45.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$312.24	$0.00	$0.00	$357.24
2027	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$22.70	$0.00	$0.00	$22.70
2028	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
2029	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
2030	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$62.00	$0.00	$0.00	$62.00
2031	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
2032	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
2033	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
2034	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
2035	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
2036	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
2037	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
2038	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
2039	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
2040	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$8.33	$0.00	$0.00	$8.33
Total	$631.79	$6,149.93	$138.89	$972.46	$763.54	$1,336.64	$64.91	$371.40	$350.54	$1,011.23	$488.17	$78.92	$66.25	$121.15	$0.00	$410.70	$392.73	$817.70	$3,104.05	$8,907.13	$17.00	$26,195.12

The role of supplemental projects in the market efficiency process needs to be modified. It is not clear how a supplemental project can be a market efficiency project that has been identified as a PJM issue based on a cost/benefit analysis and why such a project should not be subject to competition. The MMU recommends, to increase the role of competition, that the exemption of supplemental projects from the Order No. 1000 competitive process be terminated.

End of Life Transmission Projects

An end of life transmission project is a project submitted for the purpose of replacing existing infrastructure that has, or is approaching, the end of its useful life.[55] End of life transmission projects fall under the Transmission Owner Form 715 Planning Criteria, and are currently exempt from the competitive planning process.[56] End of life transmission projects are already included in the supplemental projects totals or, if included in the transmission owners' reliability plan, will be included in the baseline project list as a reliability criteria project.

55 The useful life of a transmission investment typically exceeds its depreciable life.

56 See PJM Operating Agreement Schedule 6 § 1.5.8(o).

Competitive Planning Process Exclusions

There are several project types that are currently exempt from the competitive planning process. These projects types include:

- **Immediate Need Exclusion:** Due to the immediate need of the violation (3 years or less), the timing required for an RTEP proposal window is considered to be infeasible. As a result, the local Transmission Owner is the Designated Entity.[57]
- **Below 200kV:** Due to the lower voltage level of the identified violation(s), the driver(s) for this project are currently excluded from the competitive proposal window process. As a result, the local Transmission Owner is the Designated Entity.[58]
- **FERC 715 (Transmission Owner (TO) Criteria):** Due to the violation need of this project resulting solely from FERC 715 TO Reliability Criteria, the driver(s) for this project are currently excluded from the competitive proposal window process. As a result, the local Transmission Owner is the Designated Entity.[59]
- **Substation Equipment:** Due to identification of the limiting element(s) as substation equipment, the driver(s) for this project are currently excluded from the competitive proposal window process. As a result, the local Transmission Owner is the Designated Entity.[60]

While the PJM Operating Agreement defines who will be the Designated Entity for projects that are excluded from the competitive planning process, neither the PJM Operating Agreement nor the various commission orders on transmission competition prohibit PJM from permitting competition to provide financing for such projects. The MMU recommends that rules be implemented to permit competition to provide financing for transmission projects. This competition could reduce the cost of capital for transmission projects and significantly reduce total costs to customers. In addition, the criteria for and need for all exclusions from the competitive process should be reviewed. There does not appear to be any market reason to exclude transmission projects from competition.

57 See PJM Operating Agreement Schedule 6 § 1.5.8(m).
58 See PJM Operating Agreement Schedule 6 § 1.5.8(n).
59 See PJM Operating Agreement Schedule 6 § 1.5.8(o).
60 See PJM Operating Agreement Schedule 6 § 1.5.8(p).

Cost Capping

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. On May 24, 2018, the PJM Markets and Reliability Committee (MRC) approved a motion that required PJM, with input from the MMU, to develop a comparative framework to evaluate the quality and effectiveness of binding cost containment proposals versus proposals without cost containment provisions. The proposed comparative framework, along with the advice and recommendation of the MMU, will be presented to the PJM Planning Committee for review and comment prior to an MRC vote. The comparative framework will be presented at the December 2019 meeting of the MRC.

Board Authorized Transmission Upgrades

The Transmission Expansion Advisory Committee (TEAC) regularly reviews internal and external proposals to improve transmission reliability throughout PJM. These proposals, which include reliability baseline, network, market efficiency and targeted market efficiency projects, are periodically presented to the PJM Board of Managers for authorization.[61]

An RTEP project can be approved by the PJM Board if the project ensures compliance with NERC, regional and local transmission owner planning criteria or to address market efficiency congestion relief. These projects are considered Baseline Projects. PJM Board approved RTEP projects that are necessary to allow new generation to interconnect reliably are considered Network Projects.

In 2018, $1.98 billion in additional projects were approved by the PJM Board. As of December 31, 2018, the PJM Board has approved $37.1 billion in system enhancements since 1999.

- On February 13, 2018, the PJM Board of Managers authorized an additional $328.8 million in transmission upgrades and additions.
- On April 10, 2018, the PJM Board of Managers authorized an additional $639.0 million in transmission upgrades and additions.

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

- On July 31, 2018, the PJM Board of Managers authorized an additional $629.2 million in transmission upgrades and additions.
- On October 2, 2018, the PJM Board of Managers authorized an additional $201.5 million in transmission upgrades and additions.
- On December 4, 2018, the PJM Board of Managers authorized an additional $183.6 million in transmission upgrades and additions.

Qualifying Transmission Upgrades (QTU)

A Qualifying Transmission Upgrade (QTU) is: "a proposed enhancement or addition to the transmission system that: (a) will increase the Capacity Emergency Transfer Limit into an LDA by a megawatt quantity certified by the Office of the Interconnection; (b) the Office of the Interconnection has determined will be in service on or before the commencement of the first Delivery Year for which such upgrade is the subject of a Sell Offer in the Base Residual Auction; (c) is the subject of a Facilities Study Agreement executed before the conduct of the Base Residual Auction for such Delivery Year and (d) a New Service Customer is obligated to fund through a rate or charge specific to such facility or upgrade."[62] If a QTU that was cleared in a BRA is not completed by the start of the Delivery Year, the submitting party is required to provide replacement capacity. Once a QTU is in service, the upgrade is eligible to continue to offer the approved incremental import capability into future RPM Auctions. As of December 31, 2018, no QTUs have cleared a BRA.

QTU projects are submitted and tracked through the PJM queue.[63] A total of 51 QTU projects have entered the queue since 2007. Of the 51 submitted QTU projects, 37 projects (72.5 percent) have been withdrawn, five (10.0 percent) are in service and nine (17.5 percent) are currently in active development.

62 See OATT § 1 (Qualifying Transmission Upgrade).

63 See PJM "New Services Queue," at <https://www.pjm.com/planning/services-requests/interconnection-queues.aspx>.

Transmission Facility Outages

Scheduling Transmission Facility Outage Requests

A transmission facility is designated as reportable by PJM if a change in its status can affect a transmission constraint on any Monitored Transmission Facility or could impede free flowing ties within the PJM RTO and/or adjacent areas.[64] When a reportable transmission facility needs to be taken out of service, the transmission owner is required to submit an outage request as early as possible.[65] The specific timeline is shown in Table 12-43.[66]

Transmission outages have significant impacts on PJM markets, including impacts on FTR auctions, on congestion, and on expected market outcomes in the day-ahead and real-time markets. The efficient functioning of the markets depends on clear, enforceable rules governing transmission outages.

The outage data for the FTR market are for outages scheduled to occur in the planning periods 2017/2018 and 2018/2019, regardless of when they were initially submitted.[67] The outage data for the day-ahead market are for outages scheduled to occur from January 2015 through December 2018.

Transmission outages are categorized by duration: greater than 30 calendar days; less than or equal to 30 calendar days; greater than five calendar days; less than or equal to five calendar days.[68] Table 12-42 shows that 74.4 percent of requested outages were planned for less than or equal to five days and 8.8 percent of requested outages were planned for greater than 30 days in the 2018/2019 planning period. Table 12-42 also shows that 75.9 percent of the requested outages were planned for less than or equal to five days and 7.7 percent of requested outages were planned for greater than 30 days in the 2017/2018 planning period.

64 If a transmission facility is not modeled in the PJM EMS or the facility is not expected to significantly impact PJM system security or congestion management, it is not reportable. See PJM, "Manual 3: Transmission Operations, Rev. 54 (Dec. 10, 2018).

65 See PJM, "Manual 3: Transmission Operations," Rev. 54 (Dec. 10, 2018).

66 See PJM, "Manual 3: Transmission Operations," Rev. 54 (Dec. 10, 2018).

67 The hotline tickets, EMS tripping tickets or test outage tickets were excluded. The analysis includes only the transmission outage tickets submitted by PJM companies which are currently active. The data for the reported was last run on January 31, 2019. The result will change for the 2018/2019 planning period if more outages requests are submitted after the report was created.

68 *Id.* at 70.

Table 12-42 Transmission facility outage request summary by planned duration: 2017/2018 and 2018/2019

	2017/2018		2018/2019	
Planned Duration (Days)	Outage Requests	Percent of Total	Outage Requests	Percent of Total
<=5	16,205	75.9%	12,485	74.4%
>5 & <=30	3,489	16.3%	2,821	16.8%
>30	1,652	7.7%	1,484	8.8%
Total	21,346	100.0%	16,790	100.0%

After receiving a transmission facility outage request from a TO, PJM assigns a received status to the request based on its submission date and outage planned duration. The received status can be On Time or Late, as defined in Table 12-43.[69]

The purpose of the rules defined in Table 12-43 is to require the TOs to submit transmission facility outages prior to the Financial Transmission Right (FTR) auctions so that market participants have complete information about market conditions on which to base their FTR bids and PJM can accurately model market conditions.[70]

Table 12-43 PJM transmission facility outage request received status definition

Planned Duration (Calendar Days)	Request Submitted	Received Status
<=5	Before the first of the month one month prior to the starting month of the outage	On Time
	After or on the first of the month one month prior to the starting month of the outage	Late
> 5 & <=30	Before the first of the month six months prior to the starting month of the outage	On Time
	After or on the first of the month six months prior to the starting month of the outage	Late
>30	The earlier of 1) February 1, 2) the first of the month six months prior to the starting month of the outage	On Time
	After or on the earlier of 1) February 1, 2) the first of the month six months prior to the starting month of the outage	Late

Table 12-44 shows a summary of requests by received status. In the 2018/2019 planning period, 42.8 percent of outage requests received were late. In the 2017/2018 planning period, 49.7 percent of outage requests received were late.

Table 12-44 Transmission facility outage request summary by received status: 2017/2018 and 2018/2019

	2017/2018				2018/2019			
Planned Duration (Days)	On Time	Late	Total	Percent Late	On Time	Late	Total	Percent Late
<=5	8,418	7,787	16,205	48.1%	7,375	5,110	12,485	40.9%
>5 & <=30	1,712	1,777	3,489	50.9%	1,581	1,240	2,821	44.0%
>30	609	1,043	1,652	63.1%	655	829	1,484	55.9%
Total	10,739	10,607	21,346	49.7%	9,611	7,179	16,790	42.8%

Once received, PJM processes outage requests in priority order: emergency transmission outage request; transmission outage request submitted on time; and transmission outage request submitted late. Transmission outage requests that are submitted late may be approved if the outage does not affect the reliability of PJM or cause congestion in the system.[71]

Outages with emergency status will be approved even if submitted late after PJM determines that the outage does not result in Emergency Procedures. PJM cancels or withholds approval of any outage that results in Emergency Procedures.[72] Table 12-45 is a summary of outage requests by emergency status. Of all outage requests scheduled to occur in the 2018/2019 planning period, 11.2 percent were for emergency outages. Of all outage requests scheduled to occur in the 2017/2018 planning period, 12.6 percent were for emergency outages.

69 See PJM, "Manual 3: Transmission Operations," Rev. 54 (Dec. 10, 2018).
70 See "Report of PJM Interconnection, L.L.C. on Transmission Oversight Procedures," Docket No. EL01-122-000 (November 2, 2001).
71 See PJM, "Manual 3: Transmission Operations," Rev. 54 (Dec. 10, 2018). The following language was removed from Manual 3 Rev. 50: PJM retains the right to deny all jobs submitted after 8 a.m. three days prior to the requested start date unless the request is an emergency job or an exception request (i.e. a generator tripped and the Transmission Owner is taking advantage of a situation that was not available before the unit trip).
72 PJM, "Manual 3: Transmission Operations," Rev. 54 (Dec. 10, 2018).

Table 12-45 Transmission facility outage request summary by emergency: 2017/2018 and 2018/2019

	2017/2018				2018/2019			
Planned Duration (Days)	Emergency	Non Emergency	Total	Percent Emergency	Emergency	Non Emergency	Total	Percent Emergency
<=5	2,051	14,154	16,205	12.7%	1,356	11,129	12,485	10.9%
>5 & <=30	399	3,090	3,489	11.4%	314	2,507	2,821	11.1%
>30	249	1,403	1,652	15.1%	205	1,279	1,484	13.8%
Total	2,699	18,647	21,346	12.6%	1,875	14,915	16,790	11.2%

PJM will approve all transmission outage requests that are submitted on time and do not jeopardize the reliability of the PJM system. PJM will approve all transmission outage requests that are submitted late and are not expected to cause congestion on the PJM system and do not jeopardize the reliability of the PJM system. Each outage is studied and if it is expected to cause a constraint to exceed a limit, PJM will flag the outage ticket as "congestion expected."[73]

After PJM determines that a late request may cause congestion, PJM informs the transmission owner of solutions available to eliminate the congestion. For example, if a generator planned or maintenance outage request is contributing to the congestion, PJM can request that the generation owner defer the outage. If no solutions are available, PJM may require the transmission owner to reschedule or cancel the outage.

Table 12-46 is a summary of outage requests by congestion status. Of all outage requests submitted to occur in the 2018/2019 planning period, 7.5 percent were expected to cause congestion. Of all the outage requests that were expected to cause congestion, 4.3 percent (55 out of 1,267) were denied by PJM in the 2018/2019 planning period and 20.8 percent (264 out of 1,267) were cancelled (Table 12-48). Of all outage requests submitted to occur in the 2017/2018 planning period, 7.5 percent were expected to cause congestion. Of all the outage requests that were expected to cause congestion, 3.6 percent (58 out of 1,602) were denied by PJM in the 2017/2018 planning period and 19.6 percent (314 out of 1,602) were cancelled (Table 12-48).

Table 12-46 Transmission facility outage request summary by congestion: 2017/2018 and 2018/2019

	2017/2018				2018/2019			
Planned Duration (Days)	Congestion Expected	No Congestion Expected	Total	Percent Congestion Expected	Congestion Expected	No Congestion Expected	Total	Percent Congestion Expected
<=5	1,094	15,111	16,205	6.8%	848	11,637	12,485	6.8%
>5 & <=30	357	3,132	3,489	10.2%	273	2,548	2,821	9.7%
>30	151	1,501	1,652	9.1%	146	1,338	1,484	9.8%
Total	1,602	19,744	21,346	7.5%	1,267	15,523	16,790	7.5%

Table 12-47 shows the outage requests summary by received status, congestion status and emergency status. In the 2018/2019 planning period, 31.7 percent of requests were submitted late and were nonemergency while 1.1 percent of requests (179 out of 16,790) were late, nonemergency, and expected to cause congestion. In the 2017/2018 planning period, 37.1 percent of request were submitted late and were nonemergency while 1.4 percent of requests (297 out of 21,346) were late, nonemergency, and expected to cause congestion.

Table 12-47 Transmission facility outage request summary by received status, emergency and congestion: 2017/2018 and 2018/2019

		2017/2018				2018/2019			
Received Status		Congestion Expected	No Congestion Expected	Total	Percent of Tatal	Congestion Expected	No Congestion Expected	Total	Percent of Total
Late	Emergency	85	2,593	2,678	12.5%	51	1,808	1,859	11.1%
	Non Emergency	297	7,632	7,929	37.1%	179	5,141	5,320	31.7%
On Time	Emergency	3	18	21	0.1%	1	15	16	0.1%
	Non Emergency	1,217	9,501	10,718	50.2%	1,036	8,559	9,595	57.1%
Total		1,602	19,744	21,346	100.0%	1,267	15,523	16,790	100.0%

73 PJM added this definition to Manual 38 in February 2017. PJM, "Manual 38: Operations Planning," Rev. 11 (Feb. 1, 2018).

Once PJM processes an outage request, the outage request is labelled as Submitted, Received, Denied, Approved, Cancelled by Company, PJM Admin Closure, Revised, Active or Complete according to the processed stage of a request.[74] Table 12-48 shows the detailed process status for outage requests only for the outage requests that are expected to cause congestion. Status Submitted and status Received are in the In Process category and status Cancelled by Company and status PJM Admin Closure are in the Cancelled category in Table 12-48. Table 12-48 shows that of all the outage requests that were expected to cause congestion, 4.3 percent (55 out of 1,267) were denied by PJM in the 2018/2019 planning period, 50.5 percent were complete and 20.8 percent (264 out of 1,267) were cancelled. Of all the outage requests that were expected to cause congestion, 3.6 percent (58 out of 1,602) were denied by PJM in the 2017/2018 planning period, 70.8 percent were complete and 19.6 percent (314 out of 1,602) were cancelled.

Table 12-48 Transmission facility outage requests that might cause congestion status summary: 2017/2018 and 2018/2019

		2017/2018						2018/2019					
Received Status		Cancelled	Complete	In Process	Denied	Congestion Expected	Percent Complete	Cancelled	Complete	In Process	Denied	Congestion Expected	Percent Complete
Late	Emergency	11	74	0	0	85	87.1%	5	45	1	0	51	88.2%
	Non Emergency	47	220	9	18	297	74.1%	32	104	26	13	179	58.1%
On Time	Emergency	2	1	0	0	3	33.3%	0	0	1	0	1	0.0%
	Non Emergency	254	840	76	40	1,217	69.0%	227	491	266	42	1,036	47.4%
Total		314	1,135	85	58	1,602	70.8%	264	640	294	55	1,267	50.5%

There are clear rules defined for assigning On Time or Late status for submitted outage requests in both the PJM Tariff and PJM Manuals.[75] However, the On Time or Late status only affects the priority that PJM assigns for processing the outage request. Table 12-48 shows that in the 2017/2018 planning period, 297 nonemergency outage requests were submitted late and expected to cause congestion. The expected impact on congestion is the basis for PJM's treatment of late outage requests. But there is no rule or clear definition of this congestion analysis in the PJM Manuals. The MMU recommends that PJM draft a clear definition of the congestion analysis required for transmission outage requests to include in Manual 3 after appropriate review.

Rescheduling Transmission Facility Outage Requests

A TO can reschedule or cancel an outage after initial submission. Table 12-49 is a summary of all the outage requests planned for the planning periods 2017/2018 and 2018/2019 which were approved and then cancelled or rescheduled by TOs at least once. If an outage request was submitted, approved and subsequently rescheduled at least once, the outage request will be counted as Approved and Rescheduled. If an outage request was submitted, approved and subsequently cancelled at least once, the outage request will be counted as Approved and Cancelled. In the 2018/2019 planning period, 26.3 percent of transmission outage requests were approved by PJM and then rescheduled by the TOs, and 9.8 percent of the transmission outages were approved by PJM and subsequently cancelled by the TOs. In the 2017/2018 planning period, 32.6 percent of transmission outage requests were approved by PJM and then rescheduled by the TO, and 12.5 percent of the transmission outages were approved by PJM and subsequently cancelled by the TO.

74 See PJM Markets & Operations, PJM Tools "Outage Information," <http://www.pjm.com/markets-and-operations/etools/oasis/system-information/outage-info.aspx> (2017).

75 PJM Operating Agreement Schedule 1 § 1.9.2.

Table 12-49 Rescheduled and cancelled transmission outage request summary: 2017/2018 and 2018/2019

	2017/2018					2018/2019				
Planned Duration (Days)	Outage Requests	Approved and Rescheduled	Percent Approved and Rescheduled	Approved and Cancelled	Percent Approved and Cancelled	Outage Requests	Approved and Rescheduled	Percent Approved and Rescheduled	Approved and Cancelled	Percent Approved and Cancelled
<=5	16,205	3,654	22.5%	2,379	14.7%	12,485	2,401	19.2%	1,468	11.8%
>5 & <=30	3,489	2,162	62.0%	233	6.7%	2,821	1,293	45.8%	140	5.0%
>30	1,652	1,141	69.1%	66	4.0%	1,484	722	48.7%	38	2.6%
Total	21,346	6,957	32.6%	2,678	12.5%	16,790	4,416	26.3%	1,646	9.8%

If a requested outage is determined to be late and TO reschedules the outage, the outage will be revaluated by PJM again as On Time or Late.

A transmission outage ticket with duration of five days or less with an On Time status can retain its On Time status if the outage is rescheduled within the original scheduled month.[76] This rule allows a TO to reschedule within the same month with very little notice.

A transmission outage ticket with a duration exceeding five days with an On Time status can retain its On Time status if the outage is rescheduled to a future month, and the revision is submitted by the first of the month prior to the revised month in which the outage will occur.[77] This rescheduling rule is much less strict than the rule that applies to the first submission of outage requests with similar duration. When first submitted, the outage request with a duration exceeding five days needs to be submitted before the first of the month nine months prior to the month in which the outage was expected to occur. The rescheduling rule allows TOs to avoid the timing requirements associated with outages exceeding five days.

The MMU recommends that PJM reevaluate all transmission outage tickets as On Time or Late as if they were new requests when an outage is rescheduled and apply the standard rules for late submissions to any such outages.

Long Duration Transmission Facility Outage Requests

PJM rules (Table 12-43) define a transmission outage request as On Time or Late based on the planned outage duration and the time of submission. The rule has stricter submission requirements for transmission outage requests planned for longer than 30 days. In order to avoid the stricter submission requirement, some transmission owners divided the duration of outage requests longer than 30 days into shorter segments for the same equipment and submitted one request for each segment. The MMU recommends that PJM not permit transmission owners to divide long duration outages into smaller segments to avoid complying with the requirements for long duration outages.

More than one outage request can be submitted for the same transmission equipment. In order to accurately present the results, Table 12-50 shows equipment outages by the equipment instead of by outage request.

Table 12-50 shows that there were 10,659 transmission equipment planned outages in the 2018/2019 planning period, of which 1,520 were longer than 30 days, and of which 221 or 2.1 percent were scheduled longer than 30 days when the duration of all the outage requests are combined for the same equipment.

Table 12-50 Transmission outage summary: 2017/2018 and 2018/2019

		2017/2018		2018/2019	
Planned Duration (Days)	Divided into Shorter Periods	Count of Equipment with Planned Outages	Percent of Total	Count of Equipment with Planned Outages	Percent of Total
> 30	No	1,440	11.3%	1,299	12.2%
	Yes	244	1.9%	221	2.1%
<= 30		11,033	86.8%	9,139	85.7%
Total		12,717	100.0%	10,659	100.0%

Table 12-51 shows the details of long duration (> 30 days) outages when combining the duration of the outage requests for the same equipment. The actual duration of scheduled outages would be longer than 30 days if the duration of the outage requests were appropriately combined for the same equipment. An effective duration was calculated for each piece of equipment by subtracting the start date of the earliest outage request from the end date of the latest outage

76 PJM, "Manual 3: Transmission Operations," Rev. 54 (Dec. 10, 2018).
77 *Id.*

request of the equipment. In the 2018/2019 planning period, there were 216 outages with a combined duration longer than 30 days.

Table 12-51 Equipment outages: 2017/2018 and 2018/2019

	2017/2018		2018/2019	
Effective Duration of Outage	Count of Equipment with Planned Outages	Percent of Total	Count of Equipment with Planned Outages	Percent of Total
<=31	6	2.5%	5	2.3%
>31 & <=62	25	10.2%	30	13.6%
>62 & <=93	18	7.4%	20	9.0%
>93	195	79.9%	166	75.1%
Total	244	100.0%	221	100.0%

Transmission Facility Outage Analysis for the FTR Market

Transmission facility outages affect the price and quantity outcomes of FTR Auctions. The purpose of the rules governing outage reporting is to ensure that outages are known with enough lead time prior to FTR Auctions so that market participants can understand market conditions and PJM can accurately model market conditions.

There are Long Term, Annual and Monthly Balance of Planning Period auctions in the FTR Market. For each type of auction, PJM includes a set of outages to be modeled.

Annual FTR Market

The Annual FTR Market includes the Annual ARR Allocation and the Annual FTR Auction. When determining transmission outages to be modeled in the simultaneous feasibility test used in the Annual FTR Market, PJM considers all outages with planned duration longer than or equal to two months and may consider outages with planned durations shorter than two months. PJM may exercise significant discretion in selecting outages to be modeled. PJM posts an FTR outage list to the FTR web page usually at least one week before the auction bidding opening day.[78]

In the 2018/2019 planning period, 241 outage requests were included in the annual FTR market outage list and 16,549 outage requests were not included.[79] In the 2017/2018 planning period, 250 outage requests were included in the annual FTR market outage list and 21,096 outage requests were not included. Table 12-52, Table 12-53, Table 12-54 and Table 12-55 show the summary information on the modeled outage requests and Table 12-56 and Table 12-57 show the summary information on outages that were not included in the Annual FTR Market.

Table 12-52 shows that 8.3 percent of the outage requests modeled in the Annual FTR Market for the 2018/2019 planning period had a planned duration of less than two weeks and that 15.8 percent of the outage requests (38 out of 241) modeled in the Annual FTR Market for the planning period were submitted late according to outage submission rules. It also shows that 3.6 percent of the outage requests modeled in the Annual FTR Market for the 2017/2018 planning period had a planned duration of less than two weeks and that 12.8 percent of the outage requests (32 out of 250) modeled in the Annual FTR Market for the planning period were submitted late according to outage submission rules.

Table 12-52 Annual FTR market modeled transmission facility outage requests by received status: 2017/2018 and 2018/2019

	2017/2018				2018/2019			
Planned Duration	On Time	Late	Total	Percent of Total	On Time	Late	Total	Percent of Total
<2 weeks	7	2	9	3.6%	17	3	20	8.3%
>=2 weeks & <2 months	80	9	89	35.6%	71	7	78	32.4%
>=2 months	131	21	152	60.8%	115	28	143	59.3%
Total	218	32	250	100.0%	203	38	241	100.0%

Table 12-53 shows the annual FTR market modeled outage requests summary by emergency status and received status. Three of the annual FTR market modeled outages expected to occur in the 2018/2019 planning period were emergency outages. None of the modeled outages expected to occur in the 2017/2018 planning period were emergency outages.

78 PJM Financial Transmission Rights, "Annual ARR Allocation and FTR Auction Transmission Outage Modeling," <http://www.pjm.com/~/media/markets-ops/ftr/annual-ftr-auction/2017-2018/2017-2018-annual-outage-modeling.ashx> (February 21, 2017).

79 PJM's treatment of transmission outages in the FTR models is discussed in: See the *2018 State of the Market Report for PJM*, Section 13: FTRs and ARRs: Supply and Demand.

Table 12-53 Annual FTR market modeled transmission facility outage requests by emergency and received status: 2017/2018 and 2018/2019

		2017/2018				2018/2019			
Received Status	Planned Duration	Emergency	Non Emergency	Total	Percent Non Emergency	Emergency	Non Emergency	Total	Percent Non Emergency
On Time	<2 weeks	0	7	7	100.0%	0	17	17	100.0%
	>=2 weeks & <2 months	0	80	80	100.0%	0	71	71	100.0%
	>=2 months	0	131	131	100.0%	0	115	115	100.0%
	Total	0	218	218	100.0%	0	203	203	100.0%
Late	<2 weeks	0	2	2	100.0%	0	3	3	100.0%
	>=2 weeks & <2 months	0	9	9	100.0%	0	7	7	100.0%
	>=2 months	0	21	21	100.0%	3	25	28	89.3%
	Total	0	32	32	100.0%	3	35	38	92.1%

PJM determines expected congestion for both On Time and Late outage requests. A Late outage request may be denied or cancelled if it is expected to cause congestion. Table 12-54 shows a summary of requests by expected congestion and received status. Overall, none of all the annual FTR market modeled outages expected to occur in the 2018/2019 planning period and submitted late were expected to cause congestion. Of all the annual FTR market modeled outages expected to occur in the 2017/2018 planning period and submitted late, 12.5 percent (4 out of 32) were expected to cause congestion.

Table 12-54 Annual FTR market modeled transmission facility outage requests by congestion and received status: 2017/2018 and 2018/2019

		2017/2018				2018/2019			
Received Status	Planned Duration	Congestion Expected	No Congestion Expected	Total	Percent Congestion Expected	Congestion Expected	No Congestion Expected	Total	Percent Congestion Expected
On Time	<2 weeks	3	4	7	42.9%	9	8	17	52.9%
	>=2 weeks & <2 months	21	59	80	26.3%	20	51	71	28.2%
	>=2 months	40	91	131	30.5%	34	81	115	29.6%
	Total	64	154	218	29.4%	63	140	203	31.0%
Late	<2 weeks	0	2	2	0.0%	0	3	3	0.0%
	>=2 weeks & <2 months	1	8	9	11.1%	0	7	7	0.0%
	>=2 months	3	18	21	14.3%	0	28	28	0.0%
	Total	4	28	32	12.5%	0	38	38	0.0%

Table 12-55 shows that 21.8 percent of outage requests modeled in the annual FTR market for the 2018/2019 planning period and with a duration of two weeks or longer but shorter than two months were cancelled after the FTR auction was open, compared to 34.8 percent for the 2017/2018 planning period. Table 12-55 also shows that 21.0 percent of outages requests modeled in the Annual FTR Market for the 2018/2019 planning period and with a duration of two months or longer were cancelled, compared to 12.5 percent for the 2017/2018 planning period.

Table 12-55 Annual FTR market modeled transmission facility outage requests by processed status: 2017/2018 and 2018/2019

		2017/2018		2018/2019	
Planned Duration	Processed Status	Outage Requests	Percent	Outage Requests	Percent
<2 weeks	In Progress	0	0.0%	5	25.0%
	Denied	0	0.0%	0	0.0%
	Approved	0	0.0%	0	0.0%
	Cancelled	2	22.2%	2	10.0%
	Revised	0	0.0%	1	5.0%
	Active	0	0.0%	0	0.0%
	Completed	7	77.8%	12	60.0%
	Total	9	100.0%	20	100.0%
>=2 weeks & <2 months	In Progress	7	7.9%	26	33.3%
	Denied	2	2.2%	0	0.0%
	Approved	0	0.0%	1	1.3%
	Cancelled	31	34.8%	17	21.8%
	Revised	0	0.0%	0	0.0%
	Active	0	0.0%	2	2.6%
	Completed	49	55.1%	32	41.0%
	Total	89	100.0%	78	100.0%
>=2 months	In Progress	29	19.1%	41	28.7%
	Denied	0	0.0%	1	0.7%
	Approved	2	1.3%	1	0.7%
	Cancelled	19	12.5%	30	21.0%
	Revised	0	0.0%	1	0.7%
	Active	2	1.3%	31	21.7%
	Completed	100	65.8%	38	26.6%
	Total	152	100.0%	143	100.0%

More outage requests were not modeled in the Annual FTR Market than were modeled in the Annual FTR Market. In the 2018/2019 planning period, 241 outage requests were modeled and 16,549 outage requests were not modeled in the Annual FTR Market. In the 2017/2018 planning period, 250 outage requests were modeled and 21,096 outage requests were not modeled in the Annual FTR Market.

Table 12-56 shows that 6.5 percent of outage requests not modeled in the Annual FTR Auction with duration longer than or equal to two months, labelled On Time according to the rules, were submitted after the Annual FTR Auction bidding opening date for the 2018/2019 planning period compared to 23.0 percent in the 2017/2018 planning period.

Table 12-56 Transmission facility outage requests not modeled in Annual FTR Auction: 2017/2018 and 2018/2019

	2017/2018						2018/2019					
	On Time			Late			On Time			Late		
Planned Duration	Before Bidding Opening Date	After Bidding Opening Date	Percent After	Before Bidding Opening Date	After Bidding Opening Date	Percent After	Before Bidding Opening Date	After Bidding Opening Date	Percent After	Before Bidding Opening Date	After Bidding Opening Date	Percent After
<2 weeks	1,350	8,019	85.6%	282	8,547	96.8%	1,781	6,375	78.2%	237	5,617	96.0%
>=2 weeks & <2 months	567	411	42.0%	139	1,023	88.0%	680	342	33.5%	163	657	80.1%
>=2 months	134	40	23.0%	215	369	63.2%	215	15	6.5%	213	254	54.4%
Total	2,051	8,470	80.5%	636	9,939	94.0%	2,676	6,732	71.6%	613	6,528	91.4%

Table 12-57 shows that 46.5 percent of late outage requests which were not modeled in the Annual FTR Auction with duration longer than or equal to two months and submitted after the Annual FTR Auction bidding opening date were approved and completed in the 2018/2019 planning period. It also shows that 85.4 percent of late outage requests which were not modeled in the Annual FTR Auction with duration longer than or equal to two months and submitted after the Annual FTR Auction bidding opening date were approved and completed in the 2017/2018 planning period.

Table 12-57 Late transmission facility outage requests not modeled in Annual FTR Auction and submitted after annual bidding opening date: 2017/2018 and 2018/2019

	2017/2018			2018/2019		
Planned Duration	Completed Outages	Total	Percent Complete	Completed Outages	Total	Percent Complete
<2 weeks	7,111	8,547	83.2%	4,345	5,617	77.4%
>=2 weeks & <2 months	900	1,023	88.0%	442	657	67.3%
>=2 months	315	369	85.4%	118	254	46.5%
Total	8,326	9,939	83.8%	4,905	6,528	75.1%

Although the definition of late outages was developed in order to prevent outages for the planning period being submitted after the opening of bidding in the Annual FTR Auction, the rules have not functioned effectively because the rule has no direct connection to the date on which bidding opens for the Annual FTR Auction. By requiring all long-duration transmission outages to be submitted before February 1, PJM outage submission rules only prevent long-duration transmission outages from being submitted late. The rule does not address the situation in which long-duration transmission outages are submitted on time, but are rescheduled so that they are late. There is no rule to address the situation in which short-duration outages (duration <= 5 days) are submitted on time, but are changed to long-duration transmission outages after the outages are approved and active. The Annual FTR Auction model may consider transmission outages planned for longer than two weeks but less than two months. Those outages not only include long duration outages but also include outages shorter than 30 days. In those cases, PJM outage submission rules failed to prevent long duration transmission outages from being submitted late. The MMU recommends that PJM modify the rules to eliminate the approval of outage requests submitted or rescheduled after the opening of bidding in the Annual FTR Auction.

Monthly FTR Market

When determining transmission outages to be modeled in the Monthly Balance of Planning Period FTR Auction, PJM considers all outages with planned duration longer than five days and may consider outages with planned durations less than or equal to five days. PJM exercises significant discretion in selecting outages to be modeled. PJM posts an FTR outage list to the FTR webpage usually at least one week before the auction bidding opening day.[80] Table 12-58 and Table 12-59 show the summary information on outage requests modeled in the Monthly Balance of Planning Period FTR Auction and Table 12-60 and Table 12-61 show the summary information on outage requests not modeled in the Monthly Balance of Planning Period FTR Auction.

Table 12-58 shows that on average, 27.3 percent of the outage requests modeled in the Monthly Balance of Planning Period FTR Auction were submitted late according to outage submission rules in the 2018/2019 planning period. On average, 30.6 percent of the outage requests modeled in the Monthly Balance of Planning Period FTR Auction were submitted late according to outage submission rules in the 2017/2018 planning period.

Table 12-58 Monthly Balance of Planning Period FTR Auction modeled transmission facility outage requests by received status: 2017/2018 and 2018/2019

	2017/2018				2018/2019			
Month	On Time	Late	Total	Percent Late	On Time	Late	Total	Percent Late
Jun	134	116	250	46.4%	208	106	314	33.8%
Jul	83	72	155	46.5%	136	71	207	34.3%
Aug	100	73	173	42.2%	137	78	215	36.3%
Sep	394	125	519	24.1%	465	136	601	22.6%
Oct	598	162	760	21.3%	536	191	727	26.3%
Nov	453	177	630	28.1%	391	129	520	24.8%
Dec	330	142	472	30.1%	363	129	492	26.2%
Jan	194	78	272	28.7%				
Feb	214	125	339	36.9%				
Mar	391	168	559	30.1%				
Apr	444	204	648	31.5%				
May	396	203	599	33.9%				
Avg	311	137	448	30.6%	319	120	439	27.3%

Table 12-59 shows that on average, 21.0 percent of outage requests modeled in the Monthly Balance of Planning Period FTR Auction were cancelled in the 2018/2019 planning period. On average, 19.0 percent of outage requests modeled in the Monthly Balance of Planning Period FTR Auction were cancelled in the 2017/2018 planning period.

80 PJM Financial Transmission Rights, "2015/2016 Monthly FTR Auction Transmission Outage Modeling," <http://www.pjm.com/-/media/markets-ops/ftr/ftr-allocation/monthly-ftr-auctions/2015-2016-monthly-transmission-outages-that-may-cause-infeasibilities.ashx?la=en> (December 9, 2015).

Table 12-59 Monthly Balance of Planning Period FTR Auction modeled transmission facility outage requests by processed status: 2017/2018 and 2018/2019

Planning Year	Month	In Process	Denied	Approved	Cancelled	Revised	Active	Complete	Total	Percent Cancelled
2017/2018	Jun	19	5	5	52	0	64	105	250	20.8%
	Jul	11	2	8	25	0	54	55	155	16.1%
	Aug	10	0	1	27	0	64	71	173	15.6%
	Sep	67	8	13	100	3	161	167	519	19.3%
	Oct	77	2	27	142	0	201	311	760	18.7%
	Nov	39	5	10	121	2	177	276	630	19.2%
	Dec	42	4	9	97	0	74	246	472	20.6%
	Jan	29	6	9	59	0	80	89	272	21.7%
	Feb	33	1	3	63	1	108	130	339	18.6%
	Mar	66	5	15	114	3	171	185	559	20.4%
	Apr	55	1	20	115	0	202	255	648	17.7%
	May	20	11	16	108	0	145	299	599	18.0%
	Avg	39	4	11	85	1	125	182	448	19.0%
2018/2019	Jun	22	11	10	57	0	60	154	314	18.2%
	Jul	11	4	6	38	0	60	88	207	18.4%
	Aug	19	3	2	38	1	65	87	215	17.7%
	Sep	77	11	22	143	1	163	184	601	23.8%
	Oct	66	7	19	140	0	196	299	727	19.3%
	Nov	39	2	8	119	1	166	185	520	22.9%
	Dec	42	5	5	112	0	96	232	492	22.8%
	Avg	39	6	10	92	0	115	176	439	21.0%

Table 12-60 shows that on average, 10.5 percent of outage requests not modeled in the Monthly Balance of Planning Period FTR Auction, labeled On Time according to the rules, were submitted after the monthly FTR auction bidding opening dates in the 2018/2019 planning period, compared to 10.6 percent in the 2017/2018 planning period. On average, 70.4 percent of outage requests not modeled in the Monthly Balance of Planning Period FTR Auction, labeled Late according to the rules, were submitted after the Monthly Balance of Planning Period FTR Auction bidding opening dates in the 2018/2019 planning period, compared to 70.3 percent in the 2017/2018 planning period.

Table 12-60 Transmission facility outage requests that are not modeled in Monthly Balance of Planning Period FTR Auction: 2017/2018 and 2018/2019

	2017/2018						2018/2019					
	On Time			Late			On Time			Late		
	Before Bidding Opening Date	After Bidding Opening Date	Percent After	Before Bidding Opening Date	After Bidding Opening Date	Percent After	Before Bidding Opening Date	After Bidding Opening Date	Percent After	Before Bidding Opening Date	After Bidding Opening Date	Percent After
Jun	642	96	13.0%	310	847	73.2%	757	120	13.7%	389	830	68.1%
Jul	294	48	14.0%	245	608	71.3%	393	64	14.0%	271	643	70.4%
Aug	341	28	7.6%	211	651	75.5%	484	67	12.2%	260	714	73.3%
Sep	859	84	8.9%	256	599	70.1%	820	144	14.9%	283	712	71.6%
Oct	986	89	8.3%	346	867	71.5%	1,244	104	7.7%	329	945	74.2%
Nov	815	83	9.2%	364	792	68.5%	886	60	6.3%	407	859	67.9%
Dec	610	68	10.0%	324	693	68.1%	676	31	4.4%	323	670	67.5%
Jan	565	74	11.6%	286	746	72.3%						
Feb	593	49	7.6%	340	700	67.3%						
Mar	1,070	217	16.9%	340	802	70.2%						
Apr	1,203	119	9.0%	446	852	65.6%						
May	1,203	149	11.0%	464	1,083	70.0%						
Avg	765	92	10.6%	328	770	70.3%	751	84	10.5%	323	768	70.4%

Table 12-61 shows that on average, 69.2 percent of late outage requests which were not modeled in the Monthly Balance of Planning Period FTR Auction, submitted after the Monthly Balance of Planning Period FTR Auction bidding opening dates, were approved and complete in the 2018/2019 planning period, compared to 68.3 percent in the 2017/2018 planning period.

Table 12-61 Late transmission facility outage requests that are not modeled in Monthly Balance of Planning Period FTR Auction and submitted after monthly bidding opening date: 2017/2018 and 2018/2019

	2017/2018			2018/2019		
	Completed Outages	Total	Percent Complete	Completed Outages	Total	Percent Complete
Jun	622	847	73.4%	633	830	76.3%
Jul	410	608	67.4%	449	643	69.8%
Aug	473	651	72.7%	506	714	70.9%
Sep	406	599	67.8%	480	712	67.4%
Oct	595	867	68.6%	614	945	65.0%
Nov	490	792	61.9%	570	859	66.4%
Dec	508	693	73.3%	468	670	69.9%
Jan	493	746	66.1%			
Feb	457	700	65.3%			
Mar	569	802	70.9%			
Apr	560	852	65.7%			
May	731	1,083	67.5%			
Avg	526	770	68.3%	531	768	69.2%

Transmission Facility Outage Analysis in the Day-Ahead Energy Market

Transmission facility outages also affect the energy market. Just as with the FTR Market, it is critical that outages that affect the operating day are known prior to the submission of offers in the Day-Ahead Energy Market so that market participants can understand market conditions and PJM can accurately model market conditions in the day-ahead market. PJM requires transmission owners to submit changes to outages scheduled for the next two days no later than 09:30 am.[81]

There are three relevant time periods for the analysis of the impact of transmission outages on the energy market: before the day-ahead market is closed; when the day-ahead market save cases are created; and during the operating day. The list of approved or active outage requests before the day-ahead market is closed is available to market participants. The day-ahead market model uses outages included in the day-ahead market save cases as an input. The outages that actually occurred during the operating day are the outages that affect the real-time market. If the three sets of outages are the same, there is no potential impact on markets. If the three sets of outages differ, there is a potential negative impact on markets. For example, if the list of outages before the day-ahead market was closed was different from the list of outages that included in the day-ahead market save cases, the day-ahead market participant would have inconsistent outage information as what day-ahead market model used.

For example for the operating day of May 5, 2018, Figure 12-4 shows that: there were 443 approved or active outages seen by market participants before the day-ahead market was closed; there were 329 outage requests included in the day-ahead market model; there were 315 outage requests included in both sets of outage; there were 128 outage requests approved or active before the day-ahead market was closed but not included as inputs in day-ahead market model; and there were 14 outage requests included in day-ahead market model but not available to market participants prior to the day-ahead market.

Figure 12-4 Illustration of day-ahead market analysis: May 5, 2018

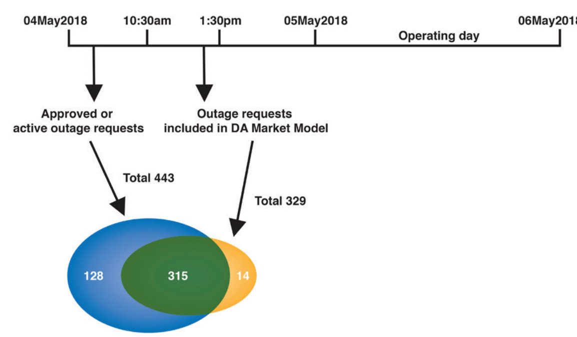


Figure 12-5 compares the weekly average number of active or approved outages available to market participants prior to the close of the day-ahead market with the outages included as inputs to the day-ahead market by PJM.

81 PJM, "Manual 3: Transmission Operations," Rev. 54 (Dec. 10, 2018).

Figure 12-5 Approved or active outage requests: January 2015 through December 2018

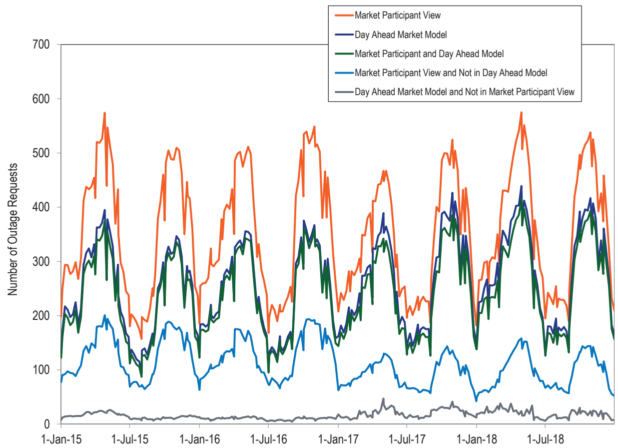


Figure 12-6 compares the weekly average number of outages included as inputs to the day-ahead market by PJM with the outages that actually occurred during the operating day.

Figure 12-6 Day-ahead market model outages: January 2015 through December 2018

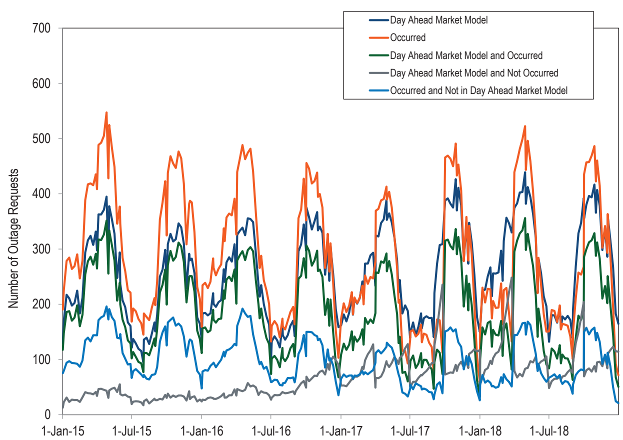


Figure 12-7 compares the weekly average number of active or approved outages available to market participants prior to the close of the day-ahead market with the outages that actually occurred during the operating day.

Figure 12-7 Approved or active outage requests: January 2015 through December 2018

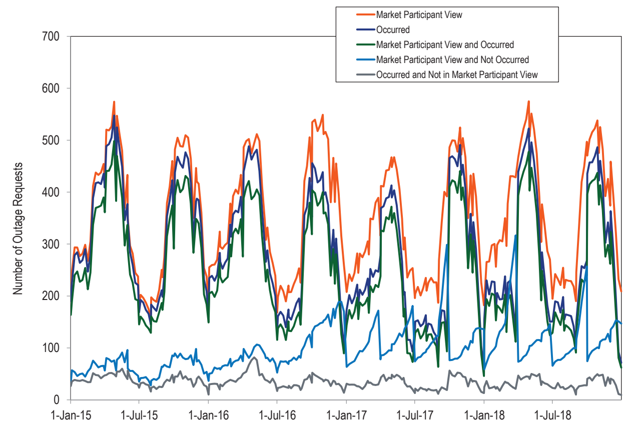


Figure 12-5, Figure 12-6, and Figure 12-7 show that on a weekly average basis, the active or approved outages available to day-ahead market participants, the outages included as inputs in the day-ahead market model and the outages that actually occurred in real time are not consistent. The active or approved outages available to day-ahead market participants are more consistent with the outages that actually occurred in real time than with the outages included in the day-ahead market model.

Financial Transmission and Auction Revenue Rights

In an LMP market, the lowest cost generation is dispatched to meet the load, subject to the ability of the transmission system to deliver that energy. When the lowest cost generation is remote from load centers, the physical transmission system permits that lowest cost generation to be delivered to load. This was true prior to the introduction of LMP markets and continues to be true in LMP markets. Prior to the introduction of LMP markets, contracts based on the physical rights associated with the transmission system were the mechanism used to provide for the delivery of low cost generation to load. Firm transmission customers who paid for the transmission system through rates or through bilateral contracts received the low cost generation.

After the introduction of LMP markets, financial transmission rights (FTRs) were introduced, effective April 1, 1999, for the real-time market and June 1, 2000, for the day-ahead and balancing markets, to permit the loads which pay for the transmission system to continue to receive the benefits of access to remote low cost generation in the form of revenues which offset congestion to the extent permitted by the transmission system.[1] FTRs and the associated congestion revenues were directly provided to load in recognition of the fact that, as a result of LMP, load pays too much for low cost generation. Under LMP, load pays and generation is paid locational prices which result in load payments in excess of generation revenues. The excess payments are congestion.

In an LMP system, the only way to ensure that load receives the benefits associated with the use of the transmission system to deliver low cost energy is to use FTRs, or an equivalent mechanism, to pay back to load the difference between the total load payments and the total generation revenues. FTRs were the mechanism selected in PJM to offset the congestion costs that load pays in an LMP market. Congestion revenues are the source of the funds to pay FTRs. Congestion revenues are assigned to the load that paid them through FTRs.[2] The only way to ensure that load receives the benefits associated with the use of the transmission system to deliver low cost energy is to ensure that all congestion revenues are returned to load.

Effective April 1, 1999, FTRs were introduced with the LMP market, there was a real-time market but no day-ahead market, and FTRs returned real-time congestion revenue to load. Effective June 1, 2000, the day-ahead market was introduced and FTRs returned total congestion including day-ahead and balancing congestion to load. Effective June 1, 2003, PJM replaced the direct allocation of FTRs to load with an allocation of Auction Revenue Rights (ARRs). Under the ARR construct, the load still owns the rights to congestion revenue, but the ARR construct allows load to either claim the FTRs directly (through a process called self scheduling), or to sell the rights to congestion revenue in the FTR auction in exchange for a revenue stream based on the auction clearing prices of the FTRs. Under the ARR construct, all FTR auction revenues should belong to the load and all of the congestion revenues should belong to those that purchase or self schedule the FTRs.

The current ARR/FTR design does not serve as an efficient way to ensure that load receives all the congestion revenues, and has the ability to receive the auction revenues associated with rights to all the potential congestion revenues. Total ARR and self scheduled FTR revenue offset only 74.5 percent of total congestion costs including congestion in the Day-Ahead Energy Market and the balancing energy market, for the 2011/2012 planning period through the 2016/2017 planning period, before the FERC decision to allocate balancing congestion and M2M payments to load.[3] For the 2017/2018 planning period, after the implementation of the FERC decision to reallocate balancing congestion and M2M payments to load, ARR and self scheduled FTR revenue offset 50.0 percent of total congestion.

A rule change was implemented to offset the more egregious effects of the allocation of balancing congestion to load.[4] Effective for the 2018/2019 planning period, surplus day-ahead congestion and surplus FTR auction revenue were allocated to ARR holders.[5]

1 See 81 FERC ¶ 61,257 at 62,241 (1997).
2 See *id.* at 62, 259–62,260 & n. 123.
3 On September 15, 2016, FERC ordered PJM to allocate balancing congestion to load, rather than to FTRs, to modify PJM's Stage 1A ARR allocation process and to continue to use portfolio netting. 153 FERC ¶ 61,180.
4 On May 31, 2018, FERC issued an order accepting PJM's proposal to allocate surplus day-ahead congestion charges and surplus FTR auction revenue that remain at the end of the Planning Period to ARR holders, rather than to FTR holders. 163 FERC ¶ 61,165.
5 163 FERC ¶61,165 (2018).

Surplus congestion revenue should be allocated to ARR holders because surplus day-ahead congestion and surplus auction revenue are associated with unallocated ARR capacity. This residual capacity is unallocated as a result of PJM's conservative modeling designed to improve FTR funding. Had this surplus allocation been implemented in the 2017/2018 planning period the percent of congestion offset by ARRs and FTRs would have increased from 50.0 percent to 74.3 percent.

The ARR/FTR design does not serve as an efficient mechanism for returning congestion to load as a result of an FTR design that was flawed from its introduction and as a result of various distortions added to the design since its introduction. The distortions include the definition of target allocations based on day-ahead congestion only, the failure to assign all FTR auction revenues to ARR holders, differences between modeled and actual system capability and numerous cross subsidies among participants. One of the flaws in the original design was the link between congestion revenues and specific generation to load transmission paths. This link retained the contract path based view of congestion rooted in physical transmission rights and inconsistent with the role of FTRs in a nodal, network system with locational marginal pricing.

If the original PJM FTR approach had been designed to return congestion revenues to load without use of the generation to load paths, and if the distortions subsequently introduced into the FTR design not been added, many of the subsequent issues with the FTR design would have been avoided. The design should simply have provided for the return of all congestion revenues to load. Now is a good time to address the issues of the FTR design and to return the design to its original purpose. This would eliminate much of the complexity associated with ARRs and FTRs and eliminate unnecessary controversy about the appropriate recipients of congestion revenues.

The 2018 State of the Market Report for PJM focuses on the 2018/2019 Long Term FTRs, 2018/2019 Annual FTR Auction, 2018/2019 Monthly Balance of Planning Period FTR Auctions, specifically covering January 1, 2018, through December 31, 2018. A caveat that applies to the 2018/2019 planning period is that the results may change depending on the final FERC actions in the GreenHat Energy, LLC matter.[6]

Table 13-1 The FTR auction markets results were competitive

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

- Market structure was evaluated as partially competitive because while purchasing FTRs in the FTR Auction is voluntary, issues have been identified with the assignment of system capability between ARRs and FTRs as well as the accuracy of modeling in the Long Term FTR Auctions. The ownership structure of Long Term FTRs, particularly the three year product, is highly concentrated.
- Participant behavior was evaluated as partially competitive based on the behavior of GreenHat Energy, LLC.
- Market performance was evaluated as competitive because it reflected the interaction between participant demand behavior and the expected system capability that PJM made available for sale as FTRs. It is not clear, in a competitive market, why FTR purchases by financial entities remain persistently profitable.
- Market design was evaluated as flawed because there are significant flaws with the basic ARR/FTR design. The market design is not an efficient or effective way to ensure that all congestion revenues are returned to load. ARR holders' rights to congestion revenues are not defined clearly enough. ARR holders cannot determine the price at which they are willing to sell rights to congestion revenue. Ongoing PJM subjective intervention in the FTR market that affects market fundamentals is also an issue.

6 See 166 FERC ¶ 61,072, *reh'g pending.*

Overview

Auction Revenue Rights

Market Structure

- **Residual ARRs.** If ARR allocations are reduced as the result of a modeled transmission outage and the transmission outage ends during the relevant planning year, the result is that residual ARRs may be available. These residual ARRs are automatically assigned to eligible participants the month before the effective date. Residual ARRs are only available on paths prorated in Stage 1 of the annual ARR allocation, are only effective for single, whole months and cannot be self scheduled. Residual ARR clearing prices are based on monthly FTR auction clearing prices. Residual ARRs with negative target allocations are not allocated to participants. Instead they are removed and the model is rerun.

  In the first seven months of the 2018/2019 planning period, PJM allocated a total of 15,463.3 MW of residual ARRs, up from 14,223.4 MW in the 2017/2018 planning period, with a total target allocation of $5.7 million for the first seven months of the 2018/2019 planning period, up from $4.8 million for the 2017/2018 planning period.

- **ARR Reassignment for Retail Load Switching.** There were 25,488 MW of ARRs associated with $301,000 of revenue that were reassigned in the first seven months of the 2018/2019 planning period. There were 44,823 MW of ARRs associated with $339,500 of revenue that were reassigned for the 2017/2018 planning period.

Market Performance

- **Revenue Adequacy.** For the first seven months of the 2018/2019 planning period, the ARR target allocations, which are based on the nodal price differences from the Annual FTR Auction, were $424.9 million, while PJM collected $895.2 million from the combined Long Term, Annual and Monthly Balance of Planning Period FTR Auctions, making ARRs revenue adequate. The new allocation of surplus congestion revenue provides for revenue adequacy for FTRs first, and any remaining revenues are allocated to ARR holders. For the 2017/2018 planning period, the ARR target allocations were $573.8 million while PJM collected $601.2 million from the combined Annual and Monthly Balance of Planning Period FTR Auctions.

- **ARRs as an Offset to Congestion.** ARRs did not serve as an effective way to return congestion revenues to load. Total ARR and self scheduled FTR revenue offset only 74.5 percent of total congestion costs, which include congestion in the Day-Ahead Energy Market and the balancing energy market, for the 2011/2012 planning period through the 2016/2017 planning period, under the previous allocation of balancing congestion. In the 2017/2018 planning period, in which balancing congestion and M2M payments were directly assigned to load, total ARR and self scheduled FTR revenues offset 50.0 percent of total congestion costs. Under the new rules for surplus congestion revenue allocation beginning in the 2018/2019 planning periods, ARRs, self scheduled FTRs and surplus congestion revenue would offset 74.2 percent of total congestion costs. The goal of the FTR market design should be to ensure that load has the rights to 100 percent of the congestion revenues.

Financial Transmission Rights

Market Structure

- **Supply.** In a given auction, market participants can sell FTRs that they have acquired in preceding auctions. In the Monthly Balance of Planning Period FTR Auctions for the first seven months of the 2018/2019 planning period, total participant FTR sell offers were 5,705,610 MW, up from 3,228,291 MW for the same period during the 2017/2018 planning period.

- **Demand.** In the 2018/2021 Long Term FTR Auction, total FTR buy bids were 2,052,820 MW, down 5.7 percent from 2,176,871 MW in the previous planning period. There were 2,907,583 MW of buy and self scheduled bids in the 2018/2019 Annual FTR Auction, up 33.6 percent from 2,176,871 MW the previous planning period. The total FTR buy bids from the Monthly Balance of Planning Period FTR Auctions for the first seven months of the 2018/2019 planning period increased 3.5 percent from 14,104,482 MW for the same time period of the prior planning period, to 13,631,502 MW.

- **Patterns of Ownership.** For the 2018/2021 Long Term FTR Auction, financial entities purchased 72.0

percent of prevailing flow FTRs and 76.5 percent of counter flow FTRs. For the 2018/2019 Annual FTR Auction, financial participants purchased 66.9 percent of all prevailing flow FTRs and 84.2 percent of all counter flow FTRs. For the Monthly Balance of Planning Period Auctions, financial entities purchased 75.5 percent of prevailing flow and 82.6 percent of counter flow FTRs for January through December of 2018. Financial entities owned 70.9 percent of all prevailing and counter flow FTRs, including 63.7 percent of all prevailing flow FTRs and 81.7 percent of all counter flow FTRs during the period from January through December 2018.

Market Behavior

- **FTR Forfeitures.** For the period of January 19, 2017, through December 31, 2018, except November 2018 which is not yet settled, total FTR forfeitures were $13.1 million.
- **Credit.** There were 14 collateral defaults in 2018 not involving GreenHat Energy, LLC, for a total of $643,371. Most collateral defaults were cured promptly. There were 74 payment defaults in 2018 not involving GreenHat Energy, LLC for a total of $136,120, which resulted in the default of Amerigreen Energy, Inc. on June 12, 2018.[7]

  On June 21, 2018, GreenHat Energy, LLC was declared in default for two collateral calls totaling $2.8 million and two payment defaults totaling $3.9 million.[8] GreenHat held a large FTR position which, according to then applicable tariff provisions, must be liquidated in the FTR auctions closest to the effective dates of the positions held.[9] The net gain or loss on these liquidated positions will be added to the payment default amount that will then be allocated to PJM members according to OA Sections 15.1.2A(1) and 15.2.2. On January 30, 2019, FERC denied a waiver request filed by PJM on July 26, 2018, asking that FERC only require PJM to liquidate FTRs for the prompt months to allow member discussion on how to proceed with GreenHat's large FTR portfolio.[10] Under the assumption of a waiver, members had elected to settle GreenHat's FTR portfolio at the time the FTRs are due, so default allocation assessment charges would continue to accrue through May 2021. PJM estimates a liquidation cost to members of $250-$300 million under the tariff rules applicable at the time of the default.[11]

Market Performance

- **Volume.** The 2018/2021 Long Term FTR Auction cleared 345,506 MW (16.8 percent) of FTR buy bids, up 16.3 percent from 297,083 MW (13.6 percent) in the 2017/2020 Long Term FTR Auction. The Long Term FTR Auction also cleared 42,555 MW (17.8 percent) of FTR sell offers, compared to 36,782 (17.6 percent), a 16.7 percent increase.

  In the Annual FTR Auction for the 2018/2019 planning period 615,254 MW (21.2 percent) of buy and self schedule bids cleared, up 19.9 percent from 615,254 MW (22.3 percent) for the previous planning period. In the first seven months of the 2018/2019 planning period Monthly Balance of Planning Period FTR Auctions cleared 2,039,265 MW (14.5 percent) of FTR buy bids and 1,181,126 MW (20.7 percent) of FTR sell offers.
- **Price.** The weighted average buy bid FTR price in the 2018/2021 Long Term FTR Auction was $0.03 per MW, down from $0.04 per MW for the 2017/2020 planning period. The weighted average buy bid FTR price in the Annual FTR Auction for the 2018/2019 planning period was $0.59 per MW, up from $0.51 per MW in the 2017/2018 planning period. The weighted average buy bid cleared FTR price in the Monthly Balance of Planning Period FTR Auctions for the first seven months of the 2018/2019 planning period was $0.13, up from $0.11 per MW for the same period in the 2017/2018 planning period.
- **Revenue.** The 2018/2021 Long Term FTR Auction generated $29.6 million of net revenue for all FTRs, up from $26.7 million for the 2017/2020 Long Term FTR Auction. The 2018/2019 Annual FTR Auction generated $822.6 million in net revenue, up from $542.2 million for the 2017/2018 Annual FTR Auction. The Monthly Balance of Planning Period FTR Auctions generated $47.3 million in net revenue for all FTRs for the first seven months

7 Daugherty, Suzanne, email sent to the MC, MRC, CS and MSS email distribution list, "PJM Member Default – Amerigreen Energy, Inc.," (June 13, 2018).

8 Daugherty, Suzanne, Email sent to the MC, MRC, CS, and MSS email distribution list, "Notification of GreenHat Energy, LLC Payment Default," (June 22, 2018).

9 "PJM Manual 6: Financial Transmission Rights," Rev. 21 (Dec. 6, 2018).

10 See 166 FERC ¶ 61,072, *reh'g pending.*

11 *See* Presentation "Update on FERC Order Denying PJM's Request for Waiver re: Liquidating FTR Positions of Defaulted Member," MRC. February 21, 2019.

of the 2018/2019 planning period, up from $26.4 million for the same time period in the 2017/2018 planning period.

- **Revenue Adequacy.** FTRs were paid at 100 percent of the target allocation level for the first seven months of the 2018/2019 planning period. This level of FTR funding was at least partially a result of FERC redefining the FTR congestion calculation to exclude balancing congestion and M2M payments.
- **Profitability.** FTR profitability is the difference between the revenue received for an FTR and the cost of the FTR. In the first seven months of the 2018/2019 planning period, physical entities made $217.2 million in profits, while receiving $91.3 million in returned congestion from self scheduled FTRs, and financial entities made $93.7 million in profits.

Markets Timeline

Any PJM member can participate in the Long Term FTR Auction, the Annual FTR Auction and the Monthly Balance of Planning Period FTR Auctions.

Table 13-2 shows the date of first availability and final closing date for all annual ARR and FTR products.

Table 13-2 Annual FTR product dates

Auction	Initial Open Date	Final Close Date
2019/2022 Long Term	6/4/2018	12/12/2018
2018/2019 ARR	3/5/2018	4/6/2018
2018/2019 Annual	4/10/2018	5/7/2018

Recommendations

- The MMU recommends that the ARR/FTR design be modified to ensure that the rights to all congestion revenues are assigned to load. (Priority: High. First reported 2015. Status: Not adopted.)
- The MMU recommends that the Long Term FTR product be eliminated. (Priority: High. First reported Q3, 2018. Status: Not adopted.)
- 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. (Priority: High. First reported 2017. Status: Not adopted.)
- The MMU recommends that the 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. (Priority: High. First reported 2017. Status: Not adopted.)
- The MMU recommends that all FTR auction revenue be distributed to ARR holders monthly, regardless of FTR funding levels. (Priority: High. First reported 2015. Status: Not adopted.)
- The MMU recommends that, under the current FTR design, all congestion revenue in excess of FTR target allocations be distributed to ARR holders on a monthly basis. (Priority: High. First reported Q1, 2018. Status: Not adopted.)
- The MMU recommends that FTR auction revenues not be used to buy counter flow FTRs for the purpose of improving FTR payout ratios.[12] (Priority: High. First reported 2015. Status: Not adopted.)
- The MMU recommends that all historical generation to load paths be eliminated as a basis for allocating ARRs. (Priority: High. First reported 2015. Status: Partially adopted.)
- The MMU recommends that PJM eliminate portfolio netting to eliminate cross subsidies among FTR market participants. (Priority: High. First reported 2012. Status: Not adopted. Rejected by FERC.)
- The MMU recommends that PJM eliminate subsidies to counter flow FTRs by applying the payout ratio to counter flow FTRs in the same way the payout ratio is applied to prevailing flow FTRs. (Priority: High. First reported 2012. Status: Not adopted.)
- The MMU recommends that PJM eliminate geographic cross subsidies. (Priority: High. First reported 2013. Status: Not adopted.)
- The MMU recommends that PJM examine the mechanism by which self scheduled FTRs are allocated when load switching among LSEs occurs throughout the planning period. (Priority: Low. First reported 2011. Status: Not adopted.)
- The MMU recommends that PJM improve transmission outage modeling in the FTR auction models, including the use of probabilistic outage

12 See "PJM Manual 6: Financial Transmission Rights," Rev. 21 (Dec. 6, 2018).

modeling. (Priority: Low. First reported 2013. Status: Not adopted.)

- The MMU recommends that PJM reduce FTR sales on paths with persistent overallocation of FTRs including clear rules for what defines persistent overallocation and how the reduction will be applied. (Priority: High. First reported 2013. Status: Partially adopted, 2014/2015 planning period.)
- The MMU recommends that PJM and its members continue to review the management of a defaulted member's FTR portfolio, including options other than immediate liquidation. (Priority: High. First reported Q2, 2018. Status: Not adopted.)
- The MMU recommends that PJM continue to evaluate the bilateral indemnification rules and any asymmetries they may create. (Priority: Low. New recommendation. Status: Not adopted.)
- The MMU recommends that PJM reexamine the source and sink node combinations available in the FTR market. (Priority: High. New recommendation. Status: Not adopted.)
- 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. (Priority: High. New recommendation. Status: Not adopted.)
- The MMU recommends that the direct customer request approach for creating and allocating IARR should be eliminated from PJM's tariff. (Priority: Low. New recommendation. Status: Not adopted.)

Conclusion

The annual ARR allocation should be designed to ensure that the rights to all congestion revenues are assigned to firm transmission service customers, without requiring contract path physical transmission rights that are inconsistent with the network based delivery of power and the actual way congestion is generated in a security constrained LMP markets. The fixed charges paid for firm transmission services result in the transmission system which provides physically firm transmission service, which results in the delivery of low cost generation, which results in load paying congestion revenues, in an LMP market.

Revenue adequacy is misunderstood and generally incorrectly defined. Revenue adequacy has received a lot of attention in the PJM FTR Market and conclusions based on the incorrect definition have led to significant changes in the design of the ARR/FTR market that have distorted the function and purpose of ARRs and FTRs as a means of allocating congestion and congestion rights. Correctly defined, revenue adequacy for ARRs means that ARRs have the rights to 100 percent of congestion revenue. FTR holders, with the creation of ARRs, do not have a right to receive revenues equal to CLMP differentials on individual FTR paths.

The current ARR/FTR design does not serve as an efficient way to ensure that load receives the rights to all the congestion revenues and has the ability to receive the auction revenues associated with all the potential congestion revenues. Total ARR and self scheduled FTR revenue offset only 65.3, 90.3, 100.0, 50.0 percent of total congestion costs including congestion in the Day-Ahead Energy Market and the balancing energy market for the 2014/2015, 2015/2016, 2016/2017, 2017/2018 planning years. If surplus through December 2018 were distributed, total ARR and self scheduled FTR revenue would offset 74.2 percent of total congestion costs for the first seven months of the 2018/2019 planning period.

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

ARRs, but continued to conservatively select outages to manage FTR funding levels.

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

Load should never be required to subsidize payments to FTR holders, regardless of the reason. Such subsidies have been suggested repeatedly.[13] The FERC order of September 15, 2016, introduced a subsidy to FTR holders at the expense of ARR holders.[14] The order requires PJM to ignore balancing congestion when calculating total congestion dollars available to fund FTRs. As of the 2017/2018 planning period, as a result of the FERC order, balancing congestion and M2M payments are assigned to load, rather than to FTR holders. The Commission's order shifts substantial revenue from load to the holders of FTRs and reduces the ability of load to offset congestion. This approach ignores the fact that loads must pay both day-ahead and balancing congestion, and that congestion is defined, in an accounting sense, to equal the sum of day-ahead and balancing congestion. Eliminating balancing congestion from the FTR revenue calculation requires load to pay twice for congestion. Load will pay for the physical transmission system, will pay in excess of generator revenues and will pay negative balancing congestion again. The result will be that load will get back less than total congestion.

These changes were made in order to increase the payout to holders of FTRs who are not loads. In other words, load will continue to be the source of all the funding for FTRs, while payments to FTR holders who did not receive ARRs exceed total congestion on their FTR paths and result in profits to FTR holders. Increasing the payout to FTR holders is not a supportable market objective. FTR holders should receive actual congestion on the relevant FTR paths and PJM should not artificially restrict the available paths.

Load was made significantly worse off as a result of the changes made to the FTR/ARR process by PJM based on the FERC order of September 15, 2016. ARR revenues were significantly reduced for the 2017/2018 FTR Auction, the first auction under the new rules. ARRs and self scheduled FTRs offset 50.0 percent of total congestion costs for the 2017/2018 planning period rather than the 60.5 percent offset that would have occurred under the prior rules, a difference of $125.8 million. There was a significant amount of congestion in January 2018 which adversely affected the congestion offset value of ARRs. ARR revenue is fixed at annual auction prices, but congestion revenue varies with market conditions. If these allocation rules had been in place beginning with the 2011/2012 planning period, ARR holders would have received a total of $1,160.0 million less in congestion offsets from the 2011/2012 through the 2017/2018 planning period. The total overpayment to FTR holders for the 2011/2012 through 2017/2018 planning period would have been $1,315.1 million.

The actual underpayment to load and the overpayment to FTR holders was a result of several rules, all of which mean the transfer of revenues to FTR holders and the shifting of costs to load. Load is required to pay for balancing congestion, which significantly increases costs to load and significantly increases revenues paid to FTR holders while degrading the ability of ARRs to provide a predictable offset to congestion costs. Surplus revenues from the FTR auction are not assigned to ARR holders, but are used by PJM to clear counter flow FTRs in the Monthly FTR Auctions in order to make it possible to sell more prevailing flow FTRs. Under the prior rules, surplus revenues in the day-ahead market were assigned to FTR holders along with surplus auction revenues.

A rule change was implemented by PJM to offset the more egregious effects of the allocation of balancing congestion to load. Beginning with the 2018/2019 planning period, surplus revenues in the day-ahead market and surplus auction revenue are assigned to FTR holders only up to revenue adequacy, and then distributed to ARR holders.[15]

All congestion revenue belongs to ARR holders, and PJM's new surplus congestion allocation rule is an attempt to get closer to that goal. However, under the

13 See FERC Dockets Nos. EL13-47-000 and EL12-19-000.

14 See 156 FERC ¶ 61,180 (2016), *reh'g denied*, 156 FERC ¶ 61,093 (2017).

15 163 FERC ¶61,165 (2018).

rules, ARR holders will only be allocated this surplus after full funding of FTRs is accomplished. The new rules, while an improvement, do not fully recognize ARR holders' primary rights to surplus congestion revenue. If this rule had been in effect for the 2017/2018 planning period, ARRs and FTRs would have offset 74.3 percent of total congestion rather than 50.0 percent. For the first seven months of the 2018/2019 planning period, if the surplus auction revenue were distributed to load on a monthly basis, load would have offset 74.2 percent of congestion costs rather than 71.1 percent of their congestion costs without the surplus.

The overallocation of Stage 1A ARRs results in FTR overallocations on the same facilities. While Stage 1A overallocation has been reduced, Stage 1A ARR overallocation is a source of reduced revenue and cross subsidy.

The MMU recommends that the basis for the Stage 1A assignments be reviewed and made explicit and that the role of out of date generation to load paths be reviewed beyond the replacement of retired generation that was implemented. There is a reason that transmission is not built to address the Stage 1A overallocation issue. PJM's transmission planning process (RTEP) does not identify a need for new transmission because many of the over allocations are due to outages in the FTR model, or are flowgates, not actual system limitations. Capacity issues do not persist if the modeled outages are removed, so there is no need to expand the transmission system to support them. The Stage 1A overallocation issue is a fiction based on the use of outdated and irrelevant generation to load paths to assign Stage 1A rights that have nothing to do with actual power flows.

In addition to addressing these issues, the approach to the question of FTR funding should also examine the fundamental reasons that there has been a significant and persistent difference between day-ahead and balancing congestion. The MMU recommends that the transmission modeling in the FTR auction and persistent FTR path overallocation issues be reviewed and modifications implemented. Regardless of how these issues are addressed, funding issues that persist as a result of modeling differences and flaws in the design of the FTR Market should be borne by FTR holders operating in the voluntary FTR Market and not imposed on load through the mechanism of balancing congestion.

It is not clear, in a competitive market, why participation in the Long Term FTR Auction continues to be very low for the second and third year long term product. In a competitive market the price of Long Term FTRs would be expected to converge with the prices of Annual FTRs, but there has been a persistent, wide divergence that has made the purchase of Long Term FTRs persistently very profitable. Recent changes to improve the modeling of the next year's auction model and include an offline ARR allocation model are steps in the right direction, but do not do enough to guarantee ARR holders' rights to the congestion being auctioned in the Long Term FTR Auction.

The MMU recommends that the Long Term FTR product be eliminated. If the Long Term FTR product is not eliminated, the MMU recommends that 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. This would ensure ARR holders' rights to congestion while maintaining the ability for participants to purchase congestion offsets for future planning periods.

Auction Revenue Rights

ARR revenues result from the sale of congestion rights that belong to ARR holders. ARRs are the financial instruments through which the proceeds from FTR Auctions are allocated to load. ARR values are based on nodal price differences, established by cleared FTR bids in the Annual FTR Auction, between the ARR source and sink points in the FTR Auction.[16] ARR revenues are a function of FTR auction participants' expectations of congestion, risk, competition and available system capability. PJM has significant discretion over that level of system capability. The appropriate goals of that discretion need to be significantly limited and defined clearly in the tariff.

ARRs are available only as obligations (not options) and only as a 24 hour product. ARRs are available to the nearest 0.1 MW. The ARR target allocation is equal to

16 These nodal prices are a function of the market participants' annual FTR bids and binding transmission constraints. An optimization algorithm selects the set of feasible FTR bids that produces the most net revenue.

the product of the ARR MW and the price difference between sink and source from the Annual FTR Auction. An ARR's value, which is established from the Annual FTR Auction, can be a benefit or liability depending on the price difference between sink and source, and represents the fixed stream of revenue that an ARR holder would receive if the ARR is retained. If the combined net revenues from the Long Term, Annual and Monthly Balance of Planning Period FTR Auctions are greater than the sum of all ARR target allocations, ARRs are fully funded, otherwise, available revenue is proportionally allocated among all ARR holders. If there are auction revenues greater than the ARR target allocations, the revenue is first used to fully fund ARRs in previous months, then fully fund FTRs, and then provided to ARR holders at the end of the planning period.

The goal of the ARR/FTR design should be to provide an efficient mechanism to ensure that load receives the rights to all the congestion revenues, and has the ability to receive the auction revenues associated with all the potential congestion revenues whether through self scheduling or selling the rights to FTR holders. If ARR holders have rights to all congestion revenue and the FTR auction is the way in which ARR holders exchange rights to congestion for fixed payments, then 100 percent of the FTR auction revenue should be assigned to ARR holders. The MMU recommends that all FTR auction revenues be allocated to ARR holders.

When a new control zone is integrated into PJM, firm transmission customers in that control zone may choose to receive either an FTR allocation or an ARR allocation before the start of the Annual FTR Auction for two consecutive planning periods following their integration date. After the transition period, such participants receive ARRs from the annual allocation process and are not eligible for directly allocated FTRs. Network service users and firm transmission customers cannot choose to receive both an FTR allocation and an ARR allocation. This selection applies to the participant's entire portfolio of ARRs that sink into the new control zone. During this transitional period, the directly allocated FTRs are reallocated, as load shifts between LSEs within the transmission zone.

On December 1, 2018, PJM integrated the Ohio Valley Electric Cooperative (OVEC) as a PJM zone. In anticipation of OVEC joining PJM earlier, PJM included the OVEC zone integration into their 2018/2019 Annual ARR Allocation, so that Kyger Creek and Clifty Creek were valid source points, and the OVEC residual aggregate was added as a biddable node in the ARR model. From June 1, 2018, to December 1, 2018, any ARRs or self scheduled FTRs source at Kyger Creek and Clifty Creek resources were remapped back to the historical OVEC interface. Effective December 1, 2018, any ARRs and self scheduled FTRs which were allocated in the Annual ARR Allocation to the OVEC interface were remapped back to Clifty Creek or Kyger Creek.

Incremental Auction Revenue Rights (IARRs) are ARRs made available by physical transmission system upgrades from customer funded transmission projects or from merchant transmission or generation interconnection requests. In order for a transmission project to generate IARRs, the project must create simultaneously feasible incremental market flow capability in PJM's ARR market model, over and above all system capability being used by existing allocated ARRs and/or would be used by granting any prorated outstanding ARR requests, in the ARR market model.[17]

There are three approaches to the creation and assigning of IARRs: IARRs can be requested by customers, which requires the customer to build sufficient transmission to support the request; IARRs can be the granted as a result of customer transmission projects such as merchant transmission or generation interconnection projects; and IARRs can be the result of RTEP upgrades. In each case, the customer(s) paying for the upgrades are allocated the IARR that are created.

The direct customer request approach for creating and allocating IARR should be eliminated from PJM's tariff. Given the current allocation of existing ARRs relative to system capability, the upgrades needed to produce any quantity of IARR under this approach are prohibitively expensive and impractical. The PJM process is not sufficiently transparent for a potential customer to make a rational decision about a potential IARR project. Much of the information required to determine whether a particular IARR project is economically viable is confidential and proprietary to incumbent transmission

17 See PJM Incremental Auction Revenue Rights Model Development and Analysis, PJM June 12, 2017. <https://www.pjm.com/~/media/markets-ops/ftr/pjm-iarr-model-development-and-analysis.ashx>.

companies including the nature and cost of any required upgrades.

IARRs are appropriately allocated to customers that have been assigned cost responsibility for certain upgrades included in the PJM's Regional Transmission Expansion Plan (RTEP). These customers as defined in Schedule 12 of the Tariff are network service customers and/or merchant transmission facility owners that are assigned the cost responsibility for upgrades included in the PJM RTEP. PJM calculates IARRs for each regionally assigned facility and allocates the IARRs, if any are created by the upgrade, to eligible customers based on their percentage of cost responsibility. The customers may choose to decline the IARR allocation during the annual ARR allocation process.[18] Each network service customer within a zone is allocated a share of the IARRs in the zone based on their share of the network service peak load of the zone.

Market Structure

ARRs have been available to network service and firm, point to point transmission service customers since June 1, 2003, when the annual ARR allocation was first implemented for the 2003/2004 planning period. The initial allocation covered the Mid-Atlantic Region and the APS Control Zone. For the 2006/2007 planning period, the choice of ARRs or direct allocation FTRs was available to eligible market participants in the AEP, DAY, DLCO and Dominion control zones. For the 2007/2008 and subsequent planning periods through the present, all eligible market participants were allocated ARRs.

Supply and Demand

System capability available to ARR holders is limited by the system capability made available in PJM's annual FTR transmission system market model. PJM's annual FTR transmission market model represents annual, expected system capability, modified by PJM to achieve PJM's goal of guaranteeing revenue equal to target allocations for FTRs, and subject to the requirement that all Stage1A ARR requests must be allocated. Stage 1A ARR right requests are guaranteed and system capability necessary to accommodate the rights must be included in PJM's annual FTR transmission system market model.

18 "PJM Manual 6: Financial Transmission Rights," Rev. 21 (Dec. 6, 2018); "IARRs for RTEP Upgrades Allocated for 2016/2017 Planning Period," <http://www.pjm.com/~/media/markets-ops/ftr/annual-arr-allocation/2018-2019/2018-2019-iarrs-for-rtep-upgrades-allocated.ashx>.

ARR Allocation

For the 2007/2008 planning period, the annual ARR allocation process was revised to include Long Term ARRs that would be in effect for 10 consecutive planning periods.[19] Stage 1A ARRs can give LSEs the ability to offset their congestion costs, through the return of congestion revenues, on a long-term basis. Stage 1B and Stage 2 ARRs provide a method for ARR holders to have additional congestion revenues returned to them in the planning period over their Stage 1A allocation, but may be prorated. ARR holders can self schedule ARRs as FTRs during the Annual FTR Auction.[20]

Each March, PJM allocates annual ARRs to eligible customers in a three stage process:

- **Stage 1A.** In the first stage of the allocation, network transmission service customers can obtain ARRs, up to their share of Zonal Base Load, which is the lowest daily peak load in the prior twelve month period increased by load growth projections. The amount of Stage 1A ARRs a participant can request is based on generation to load paths that reflect generation resources that had historically served load, or their qualified replacements if the resource has retired, in the historical reference year for the zone. The historical reference year is the year prior to the creation of PJM markets, which is 1999 for the original zones, or the year in which a zone joined PJM. Firm, point to point transmission service customers can obtain Stage 1A ARRs, up to 50 percent of the MW of firm, point to point transmission service provided between the receipt and delivery points for the historical reference year. Stage 1A ARRs cannot be prorated. If Stage 1A ARRs are found to be infeasible, transmission system upgrades must be undertaken to maintain feasibility.[21]
- **Stage 1B.** Transmission capacity unallocated in Stage 1A is available in the Stage 1B allocation for the planning period. Network transmission service customers can obtain ARRs up to their share of zonal peak load, which is the highest daily peak load in the prior twelve month period increased by load growth projections, based on generation to load

19 See *2006 State of the Market Report* (March 8, 2007) for the rules of the annual ARR allocation process for the 2006 to 2007 and prior planning periods.

20 OATT Attachment K 7.1.1.(b).

21 See "PJM Manual 6: Financial Transmission Rights," Rev. 21 (Dec. 6, 2018).

paths and up to the difference between their share of zonal peak load and Stage 1A allocations. Firm, point to point transmission service customers can obtain ARRs based on the MW of long-term, firm, point to point service provided between the receipt and delivery points for the historical reference year.

- **Stage 2.** Stage 2 of the annual ARR allocation allocates the remaining system capability equally in three steps. Network transmission service customers can obtain ARRs from any hub, control zone, generator bus or interface pricing point to any part of their aggregate load in the control zone or load aggregation zone up to their total peak network load in that zone. Firm, point to point transmission service customers can obtain ARRs consistent with their transmission service as in Stage 1A and Stage 1B.

Prior to the start of the Stage 2 annual ARR allocation process, ARR holders can relinquish any portion of their ARRs resulting from the Stage 1A or Stage 1B allocation process, provided that all remaining outstanding ARRs are simultaneously feasible following the return of such ARRs.[22] Participants may seek additional ARRs in the Stage 2 allocation.

Effective for the 2015/2016 planning period, when residual zone pricing was introduced, an ARR will default to sinking at the load settlement point if different than the zone, but the ARR holder may elect to sink their ARR at the zone instead.[23]

ARRs can be traded between LSEs prior to the first round of the Annual FTR Auction. Traded ARRs are effective for the full 12 month planning period.

When ARRs are allocated after Stage 1A, all ARRs must be simultaneously feasible, meaning that the modeled transmission system can support the approved set of ARRs. In making simultaneous feasibility determinations, PJM utilizes a power flow model of security constrained dispatch based on assumptions about generation and transmission outages.[24] If the requested set of ARRs is not simultaneously feasible, customers are allocated prorated shares in direct proportion to their requested MW and in inverse proportion to their impact on binding constraints, except Stage 1A ARRs:

Equation 13-1 Calculation of prorated ARRs[25]

$$MW = Constraint\ Capability\ x$$
$$\left(\frac{Individual\ Requested\ MW}{Total\ Requested\ MW}\right) x \left(\frac{1}{MW\ impact\ on\ line}\right)$$

The effect of an ARR request on a binding constraint is measured using the ARR's power flow distribution factor. An ARR's distribution factor is the percent of each requested ARR MW that would have a power flow on the binding constraint. The PJM method prorates ARR requests in proportion to their MW value and the impact on the binding constraint. The PJM method prorates only ARRs that cause the greatest flows on the binding constraint. Were all ARR requests prorated equally, regardless of their impact on the binding constraints, the result would reduce allocated ARRs below actually available ARRs.

FERC Order EL16-121: Stage 1A ARR Allocation

FERC ordered PJM to remove retired resources from the generation to load paths used to allocate Stage 1A ARRs.[26] PJM replaced retired units with operating generators, termed qualified replacement resources (QRRs).[27]

The method PJM implemented continues to rely on a contract path based approach. Existing Stage 1A resources will be given their current allocations, while ARR allocations to QRRs that replace retired Stage 1A resources will be prorated based on the feasibility of these ARRs after existing resources are allocated. As a result of this proration, the new ARRs will have lower priority than the preexisting Stage 1A resources, which could affect the value of the newly assigned ARRs. Generation to load paths, even from active generators, are based on a contract path model rather than a network model. Generation to load paths should not be used as a basis for assigning ARR capability. Contract paths are not an accurate representation of the reasons that congestion is

22 *Id.* at 21.

23 *See* "Residual Zone Pricing," PJM Presentation to the Members Committee (February 23, 2012) <http://www.pjm.com/~/media/committees-groups/committees/mc/20120223/20120223-item-03-residual-zone-pricing-presentation.ashx>.

24 "PJM Manual 6: Financial Transmission Rights," Rev. 21 (Dec. 6, 2018) .

25 See the *MMU Technical Reference for PJM Markets*, at "Financial Transmission Rights and Auction Revenue Rights," for an illustration explaining this calculation in greater detail. <http://www.monitoringanalytics.com/reports/Technical_References/references.shtml>.

26 156 FERC ¶ 61,180 (2016).

27 See FERC Docket No. EL16-6-003.

created or that load is served in a network and will, by definition, not accurately measure the exposure of load to congestion, resulting in modeling inaccuracies and revenue inadequacy.

Market Performance

Revenue

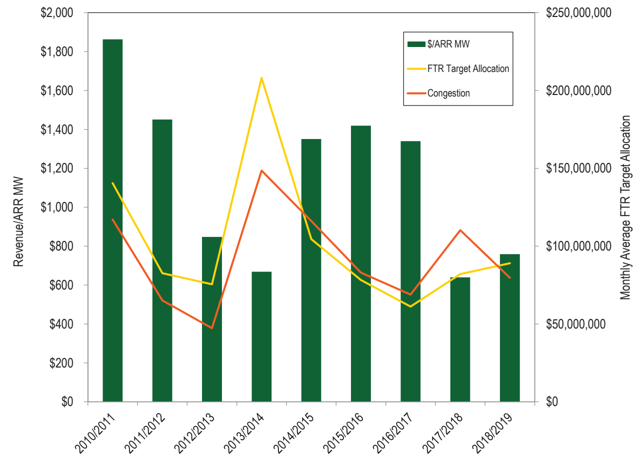
ARRs are allocated to qualifying customers rather than sold, so there is no ARR revenue comparable to the revenue that results from the FTR auctions.

Figure 13-1 shows the revenue per ARR MW held for each month of the 2010/2011 planning period through the 2017/2018 planning period. The revenue per ARR MW held do not include self scheduled FTRs' target allocation related payouts, but do include Residual ARRs starting in August 2012.

FTR prices increased in the 2014/2015 Annual FTR Auction in part as a result of reduced supply caused by PJM's assumption of more outages in the model used to allocate Stage 1B and Stage 2 ARRs. The increased FTR prices resulted in an increase in revenue per ARR MW, but fewer ARR MW. For the 2014/2015 planning period, the total dollars per MW of ARR allocation was $11,279, while the previous planning period resulted in a revenue per MW of $6,692, a 68.5 percent increase in revenue per allocated ARR MW. Some of the ARR MW lost from proration were provided in the Residual ARR process, but the residual allocations are not comparable to the ARRs awarded in the annual process because residual ARR allocations change each month and cannot be self scheduled as FTRs. For the 2015/2016 planning period, the revenue per MW of ARR allocation was $10,641.54. For the 2016/2017 planning period, the revenue per MW of ARR allocation was $10,411.

The revenue per MW value of ARRs for the 2018/2019 planning period increased 17.0 percent from the previous planning period. FTRs buyers paid less in total and on a per MW basis. Figure 13-1 shows that the total congestion and FTR target allocations increased from last planning period, primarily from a very high congestion in January 2018, but that ARR value was significantly lower. Load is now paying balancing congestion costs, not accounted for in this figure, reducing revenue received by ARR holders while not receiving the asserted benefit of higher ARR value that proponents of balancing congestion reallocation had asserted would be forthcoming.

Figure 13-1 Revenue per ARR MW paid to ARR holders compared to congestion and FTR target allocations: 2010/2011 through 2018/2019



ARR Reassignment for Retail Load Switching

PJM rules provide that when load switches between LSEs during the planning period, a proportional share of associated ARRs that sink in a given control or load aggregation zone is automatically reassigned to follow that load.[28] ARR reassignment occurs daily only if the LSE losing load has ARRs with a net positive economic value. An LSE gaining load in the same control zone is allocated a proportional share of positively valued ARRs within the control zone based on the shifted load. ARRs are reassigned to the nearest 0.001 MW and may be reassigned multiple times over a planning period. Residual ARRs are also subject to reassignment. This practice supports competition by ensuring that the offset to congestion follows load, thereby removing a barrier to competition among LSEs and, by ensuring that only ARRs with a positive value are reassigned, preventing an LSE from assigning poor ARR choices to other LSEs. However, when ARRs are self scheduled as FTRs, the self scheduled FTRs do not follow load that shifts while the ARRs do follow load that shifts, and this may result in lower value of the ARRs for the receiving LSE compared to the total value held by the original ARR holder.

There were 44,823 MW of ARRs associated with $339,500 of revenue that were reassigned in the

28 See "PJM Manual 6: Financial Transmission Rights," Rev. 21 (Dec. 6, 2018).

2017/2018 planning period. There were 25,488 MW of ARRs associated with $301,000 of revenue that were reassigned for the first seven months of the 2018/2019 planning period.

Table 13-3 summarizes ARR MW and associated revenue reassigned for network load in each control zone where changes occurred between June 2017 and December 2018.

Table 13-3 ARRs and ARR revenue automatically reassigned for network load changes by control zone: June 2017 through December 2018

	ARRs Reassigned (MW-day)		ARR Revenue Reassigned [Dollars (Thousands) per MW-day]	
Control Zone	2017/2018 (12 months)	2018/2019 (7 months)	2017/2018 (12 months)	2018/2019 (7 months)
AECO	438	264	$3.2	$1.3
AEP	2,271	2,151	$13.0	$26.8
APS	1,660	557	$19.7	$10.4
ATSI	6,235	3,104	$20.6	$32.3
BGE	2,688	1,371	$57.7	$35.3
ComEd	4,519	2,276	$77.0	$30.9
DAY	1,565	508	$2.8	$2.6
DEOK	4,318	1,778	$23.4	$44.3
DLCO	5,995	3,461	$18.5	$34.7
DPL	1,865	1,228	$36.5	$27.3
Dominion	13	22	$0.1	$0.2
EKPC	0	0	$0.0	$0.0
JCPL	1,146	690	$2.4	$1.0
Met-Ed	678	396	$5.6	$3.1
PECO	3,226	2,463	$11.1	$16.8
PENELEC	696	398	$7.3	$4.6
PPL	3,447	2,933	$3.2	$6.7
PSEG	1,495	740	$18.6	$9.0
Pepco	2,423	1,125	$18.9	$13.7
RECO	147	25	$0.0	$0.0
Total	44,823	25,488	$339.5	$301.0

Residual ARRs

Introduced August 1, 2012, Residual ARRs are available for eligible ARR holders when a transmission outage was modeled in the Annual ARR Allocation, but the transmission facility returns to service during the planning period. Residual ARRs are effective for single months, and cannot be self scheduled. Residual ARR target allocations are based on the clearing prices from FTR obligations in the relevant monthly auction, may not exceed zonal network services peak load or firm transmission reservation levels and are only available up to the prorated ARR MW capacity as allocated in the Annual ARR Allocation. For the following planning period, these Residual ARRs are available as ARRs in the annual ARR allocation. Residual ARRs are a separate product from incremental ARRs. Beginning with the June 2017 monthly auction, Residual ARRs that would have cleared with a negative target allocation are not assigned to participants.[29]

Table 13-4 shows the Residual ARRs (cleared volume) allocated to participants, along with the target allocations (bid and requested) from the effective month. In the first seven months of the 2018/2019 planning period, PJM allocated a total of 15,463.3 MW of Residual ARRs with a target allocation of $5.7 million. In the same time period for the 2017/2018 planning period, PJM allocated a total of 14,223.4 MW of residual ARRs with a target allocation of $4.8 million. In the 2016/2017 planning period planning period, PJM allocated a total of 35,034.9 MW of residual ARRs, up from 30,118.1 MW for the 2015/2016 planning period. Residual ARRs had a total target allocation of $7.0 million for the 2016/2017 planning period, down from $7.7 million for the 2015/2016 planning period. In prior planning years, PJM's modeling of excess outages resulted in the allocation of some ARRs that could have been allocated in Stage 1B being allocated as Residual ARRs on a month to month basis without the option to self schedule.

Table 13-4 Residual ARR allocation volume and target allocation: 2018

Month	Available Volume (MW)	Cleared Volume (MW)	Cleared Volume	Target Allocation
Jan-18	8,482.2	3,230.5	38.1%	$2,374,862
Feb-18	6,294.5	3,374.1	53.6%	$4,487,761
Mar-18	12,099.3	3,056.6	25.3%	$1,142,173
Apr-18	9,525.1	3,090.4	32.4%	$660,302
May-18	5,259.6	3,339.7	63.5%	$966,525
Jun-18	2,016.0	1,633.8	81.0%	$795,709
Jul-18	3,232.0	2,251.9	69.7%	$750,500
Aug-18	3,040.8	2,271.3	74.7%	$780,765
Sep-18	3,673.0	2,672.6	72.8%	$1,822,422
Oct-18	6,528.3	2,253.6	34.5%	$312,238
Nov-18	5,256.8	2,109.1	40.1%	$272,440
Dec-18	2,512.2	2,271.0	90.4%	$943,426
Total	67,919.8	31,554.6	46.5%	$15,309,124

Financial Transmission Rights

FTRs are financial instruments that entitle their holders to receive revenue or require them to pay charges based on locational congestion price differences in the Day-Ahead Energy Market across specific FTR transmission paths. The value of the day-ahead congestion price differences, termed the FTR target allocation, defines the maximum, but not guaranteed, payout for FTRs. The target allocation of an FTR reflects the difference in

29 See FERC Letter Order, Docket No. ER17-1057 (April 5, 2017).

day-ahead congestion prices rather than the difference in LMPs, which includes both congestion and marginal losses. Negative target allocations require the FTR holder to pay into the FTR market, helping fund positively valued FTRs. With the reallocation of balancing congestion and M2M payments to load, available revenue to pay FTR holders in a given month is based on the amount of day-ahead congestion, payments by holders of negatively valued FTRs, additional auction revenues available at the end of a month over ARR target allocations, any charges made to day-ahead operating reserves and any surplus revenue from preceding months in these categories. At the end of the planning period, any surplus revenue from these categories is distributed proportionally to ARR holders.

FTR funding is not on a path specific basis or on an hour to hour basis. There are widespread cross subsidies paid to equalize payments across paths and across time periods within a planning period. All paths receive the same proportional level of target revenue at the end of the planning period because if the FTR market is revenue inadequate for the planning period, each participant is charged an FTR uplift proportional to their FTR target allocations. FTR auction revenues and excess revenues are carried forward from prior months and distributed back from later months. At the end of a planning period, if some months remain not fully funded, an uplift charge is collected from any FTR Market participants that hold FTRs for the planning period based on their pro rata share of total net positive FTR target allocations, excluding any charge to FTR holders with a net negative FTR position for the planning year.

Auction market participants are free to request FTRs between any eligible pricing nodes on the system. For the Long Term FTR Auction there is a more restricted set of available hubs, control zones, aggregates, generator buses and interface pricing points available. For the Annual FTR Auction and FTRs bought for a quarterly period in the monthly auction, the available FTR source and sink points include hubs, control zones, aggregates, generator buses, load buses and interface pricing points. An FTR bought in the Monthly FTR Auction for any single calendar month following that auction may include any bus for which an LMP is calculated in the FTR model used. PJM does not allow FTR buy bids to clear with a price of zero unless there is at least one constraint in the auction which affects the FTR path. FTRs are available to the nearest 0.1 MW. The FTR target allocation is calculated hourly and is equal to the product of the FTR MW and the congestion price difference between sink and source that occurs in the Day-Ahead Energy Market.

On December 1, 2018, PJM integrated the Ohio Valley Electric Cooperative (OVEC) joined PJM as a zone. Any FTRs mapped to the previous OVEC interface were remapped to the OVEC zonal aggregate, which is the same definition as the current OVEC interface. The OVEC interface was only available for sell offers beginning in the December 2018 Monthly FTR Auction and is no longer biddable.

Market Structure

FTRs can be bought, sold and self scheduled. Buy bids are bids to buy FTRs in the auctions; sell offers are offers to sell existing FTRs in the auctions; and self scheduled bids are FTRs that have been directly converted from ARRs in the Annual FTR Auction. Self scheduled FTRs represent the choice by an ARR holder to be paid based on actual day-ahead congestion revenue rather than the fixed ARR value determined in the annual FTR auction.

There are two types of FTR products: obligations and options. An obligation provides a credit, positive or negative, equal to the product of the FTR MW and the congestion price difference between FTR sink (destination) and source (origin) that occurs in the Day-Ahead Energy Market. An option provides only positive credits and options are available for only a subset of the possible FTR transmission paths.

There are three classes of FTR products: 24 hour, on peak and off peak. The 24 hour products are effective 24 hours a day, seven days a week, while the on peak products are effective during on peak periods defined as the hours ending 0800 through 2300, Eastern Prevailing Time (EPT) Mondays through Fridays, excluding North American Electric Reliability Council (NERC) holidays. The off peak products are effective during hours ending 2400 through 0700, EPT, Mondays through Fridays, and during all hours on Saturdays, Sundays and NERC holidays.

PJM operates three types of auction for FTRs. The objective function of all FTR auctions is to maximize the bid based value of FTRs awarded in each auction. PJM conducts an Annual FTR Auction, Monthly Balance of Planning Period FTR Auctions for the remaining months of the planning period and a Long Term FTR Auction for the following three consecutive planning years.[30] FTR options are not available in the Long Term FTR Auction.

A self scheduled FTR must have the same source and sink points as the ARR and be a 24 hour obligation product. Self scheduled FTRs may not designate a price bid; rather their price is determined by the clearing price in the annual FTR auction. From a settlements perspective, the self scheduling participant is paid their ARR target allocation, which is then immediately used to pay their FTR's buy price. The participant then receives the hourly congestion LMP difference of their source and sink points as any other FTR would.

A secondary bilateral market is also administered by PJM to allow participants to buy and sell existing FTRs. FTRs can also be exchanged bilaterally outside PJM markets. FTR self scheduled bids by ARR holders are available only as obligations for the 24 hour product and only in the Annual FTR Auction.

Supply and Demand

Total FTR supply is limited by the capability of the transmission system, in each auction, included in the PJM FTR market model as modified, for example, by PJM assumptions about outages. PJM may also limit available capability through subjective judgment exercised without any clear guidelines. PJM outage assumptions are a key factor in determining the supply of ARRs and the related supply of FTRs in the Annual FTR Auction. Long Term FTR Auction capability is determined by removing all outages and running an offline model of the previous Annual FTR Auction model with all ARR bids. Any ARR MW that clear are reserved for ARR holders in their effective planning periods, and are removed from the Long Term FTR Auction capability. This does not, and cannot, preserve all possible capacity for ARR holders before a long term auction due to changes in system topology and outage selection between planning periods. Total Monthly FTR Auction capacity is based on the residual capacity available after the Long Term and Annual FTR auctions are conducted and adjustments are made to outages to reflect anticipated system conditions for the time periods auctioned.

The MMU recommends that the full transmission capacity of the system be allocated as ARRs prior to sale as FTRs.

Depending on assumptions used in the auction transmission model, the total FTR supply can be greater than or less than system capability in aggregate and/or on a path basis. FTR supply greater than system capability contributes to FTR revenue inadequacy relative to target allocations. FTR supply less than system capability contributes to FTR revenue surplus relative to target allocations.

PJM can also make further subjective adjustments to the auction model to manage FTR revenues. PJM can assume arbitrarily higher outage levels and PJM can decide to include additional constraints (closed loop interfaces) both of which reduce system capability in the auction model. These PJM actions reduce the supply of available Stage 1B and Stage 2 ARRs, which in turn reduce the number of FTRs available for purchase. PJM made very significant adjustments starting in the 2014/2015 planning period auction model through the 2016/2017 planning period.

The auction process does not account for the fact that significant transmission outages, which have not been provided to PJM by transmission owners prior to the auction date, will occur during the periods covered by the auctions. Such transmission outages may or may not be planned in advance or may be emergency outages.[31] In addition, it is difficult to model in an annual auction two outages of similar significance and similar duration in different areas which do not overlap in time. The choice of which to model may have significant distributional consequences. The fact that outages are modeled at significantly lower than historical levels results in selling too many FTRs which creates downward pressure on revenues paid to each FTR. To address this issue, the MMU recommends that PJM use probabilistic outage modeling to better align the supply of ARRs and FTRs with actual system capabilities.

30 *See* "PJM Manual 6: Financial Transmission Rights," Rev. 21 (Dec. 6, 2018).

31 See the *2018 State of the Market Report for PJM*, Section 12: Transmission Facility Outages: Transmission Facility Outages Analysis for the FTR Market.

Long Term FTR Auctions

In July 2006, FERC issued a Final Rule mandating the creation of long term firm transmission rights in transmission organizations with organized electricity markets (FERC Docket No. RM06-8-000; Order No. 681).[32] FERC's goal was that "load serving entities be able to request and obtain transmission rights up to a reasonable amount on a long-term firm basis, instead of being limited to obtaining exclusively annual rights." Despite that order and inconsistent with the directive in that order, LSEs are not able to request ARRs nor are LSEs guaranteed rights to the revenue from Long Term FTR Auctions in PJM's long term FTR auction market design.

PJM conducts a Long Term FTR Auction for the next three consecutive planning periods. The capacity offered for sale in Long Term FTR Auctions is the residual system capability assuming that all allocated ARRs are self scheduled as FTRs. PJM expands the available transmission capacity for the Long Term FTR Auction by removing all the transmission outages included in the model when allocating ARRs.

Beginning with Round 2 of the 2019/2022 Long Term FTR Auction, PJM has implemented revisions to the determination of residual system capability made available in the Long Term FTR Auctions, and eliminated the YRALL product, consistent with the MMU's recommendation. The PJM proposal revises the determination of ARR rights that are reserved for ARR holders. Rather than simply preserving the ARR cleared capacity from the previous annual allocation, PJM would rerun the simultaneous feasibility test for the ARR/FTR market model, without outages, using the previous year's ARR requests, prorated when necessary, and use the resulting ARRs as the basis for reserving capability for ARR holders in the Long Term FTR Auction. The resulting difference between the revised set of ARRs and ARR/FTR market models' system capability, without outages, would determine the residual capability offered in the Long Term FTR auction. This method will provide ARR holders with a more accurate representation of capacity that will carry into the Annual FTR Auction than is currently preserved for ARR holders. Capacity awarded in the Long Term FTR Auction is modeled as a fixed injection/withdrawal in the Annual FTR Auction, and is therefore unavailable in preceding auctions. While the new rules will improve the allocation of congestion rights to ARR holders, a proportion of congestion revenues will still be assigned to the Long Term FTR Auction without ever having been made available to ARR holders. Due to the duration of long term FTRs and the inconstant nature of the ARR/FTR model's outage selections and system topology, reserving the previous year's ARR bids does not fully capture all of the capability that should be available to ARR holders. Any capability that is auctioned in the Long Term FTR Auction and that should otherwise be available to ARR holders results in lost revenue to ARR holders. That outcome is inconsistent with the basic logic of ARRs and inconsistent with the stated intent of the market design.

The 2009/2012 and 2010/2013 Long Term FTR Auctions consisted of two rounds.[33] Subsequent Long Term FTR Auctions consist of three rounds. FTRs purchased in prior rounds may be offered for sale in subsequent rounds. FTRs obtained in the Long Term Auctions may have terms of any one of the next three. FTR products available in the Long Term Auction include 24 hour, on peak and off peak FTR obligations. FTR option products are not available in Long Term FTR Auctions.

- Round 1. The first round is conducted in the June prior to the start of the term covered by the Long Term FTR Auction and uses PJM's Summer Model build. Market participants make offers for FTRs between any source and sink.
- Round 2. The second round is conducted in September, uses the Summer Model build and follows the same rules as Round 1.
- Round 3. The third round is conducted in December, uses the Fall Model build and follows the same rules as Round 1.

Annual FTR Auctions

Annual FTRs are effective beginning June 1 of the planning period through May 31. Outages expected to last two or more months, as well as any outages of a shorter duration that PJM determines would cause FTR revenue inadequacy if not modeled, are included in the

32 116 FERC ¶ 61,077 (2006).

33 FERC approved, on December 7, 2009, the addition of a third round to the Long Term FTR Auction. FERC letter order accepting PJM Interconnection, L.L.C.'s revisions to Long-Term Financial Transmission Rights Auctions to its Amended and Restated Operating Agreement and Open Access Transmission Tariff, Docket No. ER10-82-000 (December 7, 2009).

determination of the simultaneous feasibility for the Annual FTR Auction.[34] While the full list of outages selected is publicly posted, PJM exercises significant subjective judgment in selecting outages to accomplish FTR revenue adequacy goals and the process by which these outages are selected is not clear and is not documented. ARR holders who wish to self schedule must inform PJM prior to round one of the annual auction. Any self scheduled ARR requests clear 25 percent of the requested volume in each round of the Annual FTR Auction as price takers. This auction consists of four rounds that allow any transmission service customers or PJM members to bid for any FTR or to offer for sale any FTR that they currently hold. FTRs in this auction can be obligations or options for peak, off peak or 24 hour periods. FTRs purchased in one round of the Annual FTR Auction can be sold in later rounds or in the Monthly Balance of Planning Period FTR Auctions.

The FTRs sold in the Long Term FTR Auction for a future delivery year may conflict with the ARRs assigned to load in the ARR allocation process when that delivery year is effective. By not properly reserving all ARR capacity in the Long Term FTR Auction, it is possible that a SFT violation may occur between a long term FTR and a self scheduled ARR, resulting in revenue adequacy issues.

Monthly Balance of Planning Period FTR Auctions

The residual capability of the PJM transmission system, after the Long Term and Annual FTR Auctions are concluded, is offered in the Monthly Balance of Planning Period FTR Auctions. Outages expected to last five or more days are included in the determination of the simultaneous feasibility test for the Monthly Balance of Planning Period FTR Auction. These are single-round monthly auctions that allow any transmission service customer or PJM member to bid for any FTR or to offer for sale any FTR that they currently hold. Market participants can bid for or offer monthly FTRs for any of the next three months remaining in the planning period, or quarterly FTRs for any of the quarters remaining in the planning period. FTRs in the auctions include obligations and options and 24 hour, on peak and off peak products.[35] Beginning with the 2018/2019 planning period, to address performance issues in solving the Monthly Balance of Planning Period Auctions, participants may no longer place bids that overlap three available monthly periods.[36] For example, participants cannot place a bid for Quarter 1 in the June auction because that quarter overlaps three individual month periods.

Secondary Bilateral Market

Market participants can buy and sell existing FTRs through the PJM administered, bilateral market, or market participants can trade FTRs among themselves without PJM involvement. Bilateral transactions that are not done through PJM can involve parties that are not PJM members. PJM has no knowledge of bilateral transactions that are done outside of PJM's bilateral market system.

For bilateral trades done through PJM, the FTR transmission path must remain the same, FTR obligations must remain obligations, and FTR options must remain options. However, an individual FTR may be split up into multiple, smaller FTRs, down to increments of 0.1 MW. FTRs can also be given more restrictive start and end times, meaning that the start time cannot be earlier than the original FTR start time and the end time cannot be later than the original FTR end time.

Patterns of Ownership

In order to evaluate the ownership of prevailing flow and counter flow FTRs, the MMU categorized all participants owning FTRs in PJM as either physical or financial. Physical entities include utilities and customers which primarily take physical positions in PJM markets. Financial entities include banks, trading firms and hedge funds which primarily take financial positions in PJM markets. International market participants that primarily take financial positions in PJM markets are generally considered to be financial entities even if they are utilities in their own countries.

34 See "PJM Manual 6: Financial Transmission Rights," Rev. 21 (Dec. 6, 2018).
35 See "PJM Manual 6: Financial Transmission Rights," Rev. 21 (Dec. 6, 2018).
36 PJM. "Manual 6: Financial Transmission Rights," Rev. 21 (Dec. 6, 2018).

The HHI is commonly used to measure market concentration with a HHI of 10000 indicating a monopoly. The "Merger Policy Statement" of FERC states that a market can be broadly characterized as:

- **Unconcentrated.** Market HHI below 1000, equivalent to 10 firms with equal market shares;
- **Moderately Concentrated.** Market HHI between 1000 and 1800; and
- **Highly Concentrated.** Market HHI greater than 1800, equivalent to between five and six firms with equal market shares.[37]

Table 13-5 shows the 2018/2021 long term FTR auction market cleared FTRs by trade type, organization type and FTR direction. The results show that financial entities purchased 72.0 percent of prevailing flow buy bid FTRs and 76.5 percent of counter flow buy bid FTRs with the result that financial entities purchased 74.1 percent of all long term FTR auction cleared buy bids. Physical entities purchased 25.9 percent of all cleared long term FTRs in the 2018/2021 Long Term FTR Auction.

Table 13-5 Long term FTR auction patterns of ownership by FTR direction: 2018/2021

		FTR Direction		
Trade Type	Organization Type	Prevailing Flow	Counter Flow	All
Buy Bids	Physical	28.0%	23.5%	25.9%
	Financial	72.0%	76.5%	74.1%
	Total	100.0%	100.0%	100.0%
Sell Offers	Physical	29.1%	19.5%	25.8%
	Financial	70.9%	80.5%	74.2%
	Total	100.0%	100.0%	100.0%

Table 13-6 shows the HHI for the periods in the 2016/2019 through 2018/2021 Long Term FTR Auctions. The YRALL auction is Highly Concentrated. The individual annual auctions are Unconcentrated.

Table 13-6 Long term HHIs by auction

Auction	YR1	YR2	YR3	YRALL
18/21 Auction	586	850	577	8654
17/20 Auction	462	1696	1252	8533
16/19 Auction	564	832	1048	5487

Table 13-7 shows the annual FTR auction cleared FTRs for the 2018/2019 planning period by trade type, organization type and FTR direction. In the Annual FTR Auction for the 2018/2019 planning period, financial entities purchased 66.9 percent of prevailing flow FTRs, down 10.6 percentage points, and 84.2 percent of counter flow FTRs, up 4.5 percentage points, with the results that financial entities purchased 72.8 percent, up 6.2 percentage points, of all annual FTR auction cleared buy bids for the 2018/2019 planning period.

Table 13-7 Annual FTR Auction patterns of ownership by FTR direction: 2018/2019

			FTR Direction		
Trade Type	Organization Type	Self-Scheduled FTRs	Prevailing Flow	Counter Flow	All
Buy Bids	Physical	Yes	6.2%	1.1%	4.5%
		No	26.9%	14.7%	22.7%
		Total	33.1%	15.8%	27.2%
	Financial	No	66.9%	84.2%	72.8%
	Total		100.0%	100.0%	100.0%
Sell Offers	Physical		28.1%	30.3%	29.1%
	Financial		71.9%	69.7%	70.9%
	Total		100.0%	100.0%	100.0%

Table 13-8 shows the HHI values for cleared buy and self scheduled bids for the 2016/2017 through 2018/2019 Annual FTR Auctions. Obligation buy bids are consistently Unconcentrated, while Option buy bids are Unconcentrated to Moderately Concentrated. Cleared self scheduled bids are always Highly Concentrated.

Table 13-8 Annual auction HHIs by auction

Auction	Hedge Type	Trade Type	HHI
18/19 Annual Auction	Obligation	Buy	357
	Obligation	Self Scheduled	2620
	Option	Buy	1213
17/18 Annual Auction	Obligation	Buy	303
	Obligation	Self Scheduled	2794
	Option	Buy	2099
16/17 Annual Auction	Obligation	Buy	398
	Obligation	Self Scheduled	2553
	Option	Buy	666

Table 13-9 presents the monthly balance of planning period FTR auction cleared FTRs for 2018 by trade type, organization type and FTR direction. Financial entities purchased 75.5 percent of prevailing flow FTRs, up 1.2 percentage points, and 82.6 percent of counter flow FTRs, down 0.1 percentage points, for the year, with the result that financial entities purchased 78.5 percent, up 0.2 percentage points, of all prevailing and counter flow FTR buy bids in the monthly balance of planning period FTR auction cleared FTRs for 2018.

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

Table 13-9 Monthly Balance of Planning Period FTR Auction patterns of ownership by FTR direction: 2018

		FTR Direction		
Trade Type	Organization Type	Prevailing Flow	Counter Flow	All
Buy Bids	Physical	24.5%	17.4%	21.5%
	Financial	75.5%	82.6%	78.5%
	Total	100.0%	100.0%	100.0%
Sell Offers	Physical	17.7%	18.9%	18.1%
	Financial	82.3%	81.1%	81.9%
	Total	100.0%	100.0%	100.0%

Table 13-10 shows the HHI values for cleared MW for the 2018/2019 planning period monthly auctions by period. Cleared obligation buy bids are Unconcentrated. Cleared option buy bids range from Unconcentrated to Highly Concentrated.

Table 13-10 Monthly Balance of Planning Period FTR Auction HHIs by period

Auction	Hedge Type	Prompt Month	Prompt Month+1	Prompt Month+2	Q2	Q3	Q4
Jun-18	Obligation	353	432	487	587	659	773
	Option	3796	5981	7006	4854	4761	6586
Jul-18	Obligation	329	434	1283	827	559	681
	Option	2270	5044	2751	3666	3918	6260
Aug-18	Obligation	254	534	528	509	430	522
	Option	2437	3135	4673	5486	4729	5578
Sep-18	Obligation	330	481	534		610	772
	Option	1412	4864	3118		1622	4876
Oct-18	Obligation	378	457	834		478	678
	Option	1192	1938	3884		1892	4399
Nov-18	Obligation	329	591	641		523	580
	Option	1337	1715	2610		1650	2312
Dec-18	Obligation	327	456	546			685
	Option	1255	1944	1662			2038

Table 13-11 shows the average daily net position ownership for all FTRs for 2018, by FTR direction.

Table 13-11 Daily FTR net position ownership by FTR direction: 2018

	FTR Direction		
Organization Type	Prevailing Flow	Counter Flow	All
Physical	36.3%	18.3%	29.1%
Financial	63.7%	81.7%	70.9%
Total	100.0%	100.0%	100.0%

Market Performance

Volume

PJM regularly intervenes in the FTR market based on subjective judgment which is not based on clear or documented guidelines. Such intervention in the FTR, or any market, is not appropriate and not consistent with the operation of competitive markets. In an apparent effort to manage FTR revenues, PJM may adjust normal transmission limits (rather than the inflated limits used in Stage 1A) in the FTR auction model. If, in PJM's judgment, the normal capability limit is not consistent with revenue adequacy goals and simultaneous feasibility, then FTR Auction capability reductions are undertaken pro rata based on the MW of Stage 1A infeasibility and the availability of auction bids for counter flow FTRs.[38] PJM may also remove or reduce infeasibilities caused by transmission outages by clearing counter flow bids without being required to clear the corresponding prevailing flow bids.[39] The use of both of these procedures is contingent on PJM actions not affecting the revenue adequacy of allocated ARRs, all requested self scheduled FTRs clear and net FTR auction revenue is positive.

Long Term FTR Auction

In the 2018/2021 Long Term FTR Auction, 164,911 MW (25.1 percent of bid volume; 47.7 percent of total FTR volume) of counter flow FTR buy bids cleared, an increase from 133,153 MW and 44.8 percent of total FTR volume. In the same auction, prevailing flow FTR buy bids cleared 180,596 MW (12.9 percent of bid volume; 52.3 percent of total FTR volume) an increase from 163,931 MW and 55.2 percent of total FTR volume. In the 2018/2021 Long Term FTR Auction, there were 14,352 MW (13.3 percent) of counter flow sell offers and 28,203 MW (21.6 percent) of prevailing flow sell offers cleared.

38 See "PJM Manual 6: Financial Transmission Rights," Rev. 21 (Dec. 6, 2018).
39 See *id.*

Table 13-12 Long Term FTR Auction market volume: 2018/2021

Trade Type	FTR Direction	Period Type	Bid and Requested Count	Bid and Requested Volume (MW)	Cleared Volume (MW)	Cleared Volume	Uncleared Volume (MW)	Uncleared Volume
Buy bids	Counter Flow	Year 1	87,872	298,519	84,499	28.3%	214,021	71.7%
		Year 2	66,734	227,741	55,012	24.2%	172,729	75.8%
		Year 3	40,971	127,769	23,873	18.7%	103,896	81.3%
		Year All	428	2,768	1,528	55.2%	1,241	44.8%
		Total	196,005	656,797	164,911	25.1%	491,886	74.9%
	Prevailing Flow	Year 1	150,441	600,107	90,472	15.1%	509,635	84.9%
		Year 2	113,148	433,669	61,073	14.1%	372,597	85.9%
		Year 3	82,846	330,783	28,551	8.6%	302,232	91.4%
		Year All	5,134	31,464	500	1.6%	30,964	98.4%
		Total	351,569	1,396,023	180,596	12.9%	1,215,428	87.1%
	Total		547,574	2,052,820	345,506	16.8%	1,707,314	83.2%
Sell offers	Counter Flow	Year 1	31,956	68,686	9,805	14.3%	58,881	85.7%
		Year 2	14,374	33,379	4,398	13.2%	28,980	86.8%
		Year 3	1,905	5,780	149	2.6%	5,632	97.4%
		Year All	NA	NA	NA	NA	NA	NA
		Total	48,235	107,845	14,352	13.3%	93,494	86.7%
	Prevailing Flow	Year 1	34,038	82,071	18,847	23.0%	63,224	77.0%
		Year 2	16,073	41,876	8,520	20.3%	33,356	79.7%
		Year 3	2,343	6,867	837	12.2%	6,030	87.8%
		Year All	NA	NA	NA	NA	NA	NA
		Total	52,454	130,813	28,203	21.6%	102,610	78.4%
	Total		100,689	238,659	42,555	17.8%	196,104	82.2%

Figure 13-2 shows the percent of FTR MW cleared, and bid and cleared volume, by direction, for each round of the Long Term FTR Auction from the 2015/2018 through the 2018/2021 auctions.

Figure 13-2 Long Term FTR Auction bid and cleared volume by round and direction

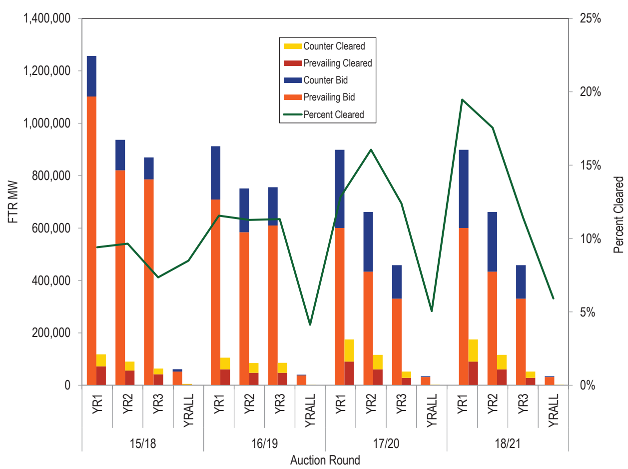


Table 13-13 compares cleared FTR obligations (not options) acquired in the Long Term FTR Auctions to the total cleared FTR obligations from the Annual FTR Auction, for FTRs in the 2014/2015 through 2018/2019 planning periods. A three year FTR is distributed to each individual planning period during its three year effective period. Long term FTRs that are effective in a single planning period were an average of 43.8 percent of total FTR volume in the 2014/2015 through 2018/2019 planning periods.

Table 13-13 Long Term and Annual Auction total cleared FTR MW

	Long Term FTR Product (Including YRALL)			Volume (MW)		
Effective Planning Period	YR3	YR2	YR1	Total Long Term	Annual (including self scheduled)	Long Term Percent of Total Cleared
2014/2015	81,666	86,754	131,911	300,330	356,522	45.7%
2015/2016	89,419	99,329	123,400	312,148	355,682	46.7%
2016/2017	97,837	95,637	107,182	300,656	397,258	43.1%
2017/2018	69,161	86,323	108,126	263,609	493,683	34.8%
2018/2019	87,232	109,827	177,018	374,078	395,506	48.6%

Annual FTR Auction

Table 13-14 shows the annual FTR auction market volume for the 2018/2019 planning period. Total FTR buy bids were 2,880,105 MW, up 26.2 percent from 2,281,534 MW for the previous planning period. For the 2018/2019 planning period 587,775 MW (20.4 percent) of buy bids cleared, down 1.0 percentage points from 488,734 MW for the previous planning period. There were 348,130 MW of sell offers with 48,545 MW (13.9 percent) clearing for the 2018/2019 planning period. The total volume of cleared buy and self scheduled bids was 615,254 MW, up 19.9 percent from 513,263 MW in the previous Annual FTR Auction.

Table 13-14 Annual FTR Auction market volume: 2018/2019

Trade Type	Type	FTR Direction	Bid and Requested Count	Bid and Requested Volume (MW)	Cleared Volume (MW)	Cleared Volume	Uncleared Volume (MW)	Uncleared Volume
Buy bids	Obligations	Counter Flow	149,479	571,352	208,160	36.4%	363,192	63.6%
		Prevailing Flow	366,227	1,956,181	314,030	16.1%	1,642,151	83.9%
		Total	515,706	2,527,533	522,190	20.7%	2,005,343	79.3%
	Options	Counter Flow	26	2,481	184	7.4%	2,297	92.6%
		Prevailing Flow	28,230	350,091	65,254	18.6%	284,837	81.4%
		Total	28,256	352,572	65,438	18.6%	287,134	81.4%
	Total	Counter Flow	149,505	573,833	208,344	36.3%	365,489	63.7%
		Prevailing Flow	394,457	2,306,272	379,284	16.4%	1,926,988	83.6%
		Total	543,962	2,880,105	587,628	20.4%	2,292,477	79.6%
Self-scheduled bids	Obligations	Counter Flow	114	2,290	2,290	100.0%	0	0.0%
		Prevailing Flow	3,158	25,189	25,189	100.0%	0	0.0%
		Total	3,272	27,479	27,479	100.0%	0	0.0%
Buy and self-scheduled bids	Obligations	Counter Flow	149,593	573,642	210,450	36.7%	363,192	63.3%
		Prevailing Flow	369,385	1,981,370	339,219	17.1%	1,642,151	82.9%
		Total	518,978	2,555,012	549,669	21.5%	2,005,343	78.5%
	Options	Counter Flow	26	2,481	184	7.4%	2,297	92.6%
		Prevailing Flow	28,230	350,091	65,254	18.6%	284,837	81.4%
		Total	28,256	352,572	65,438	18.6%	287,134	81.4%
	Total	Counter Flow	149,619	576,122	210,634	36.6%	365,489	63.4%
		Prevailing Flow	397,615	2,331,461	404,473	17.3%	1,926,988	82.7%
		Total	547,234	2,907,583	615,106	21.2%	2,292,477	78.8%
Sell offers	Obligations	Counter Flow	77,385	161,170	21,423	13.3%	139,746	86.7%
		Prevailing Flow	87,893	174,680	26,548	15.2%	148,132	84.8%
		Total	165,278	335,849	47,971	14.3%	287,878	85.7%
	Options	Counter Flow	2	55	0	0.0%	55	100.0%
		Prevailing Flow	931	12,226	556	4.5%	11,671	95.5%
		Total	933	12,281	556	4.5%	11,725	95.5%
	Total	Counter Flow	77,387	161,224	21,423	13.3%	139,801	86.7%
		Prevailing Flow	88,824	186,906	27,104	14.5%	159,802	85.5%
		Total	166,211	348,130	48,527	13.9%	299,603	86.1%

Figure 13-3 shows the percent of FTR MW cleared and bid and cleared volume, by direction, for each round of the Annual FTR Auction from the 2015/2016 planning period through the 2018/2019 planning period.

Figure 13-3 Annual FTR Auction bid and cleared volume by round and direction

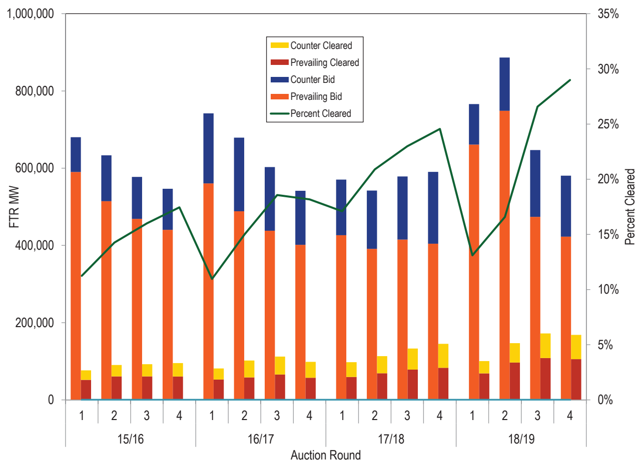


Figure 13-4 shows the proportion of ARRs self scheduled as FTRs for the last eight planning periods. The maximum possible level of self scheduled FTRs includes all ARRs. Eligible participants self scheduled 27,479 MW (27.5 percent) of ARRs as FTRs for the 2018/2019 planning period, up from 24,529 MW (25.4 percent) in the previous planning period.

Figure 13-4 Comparison of self scheduled FTRs: 2009/2010 through 2018/2019

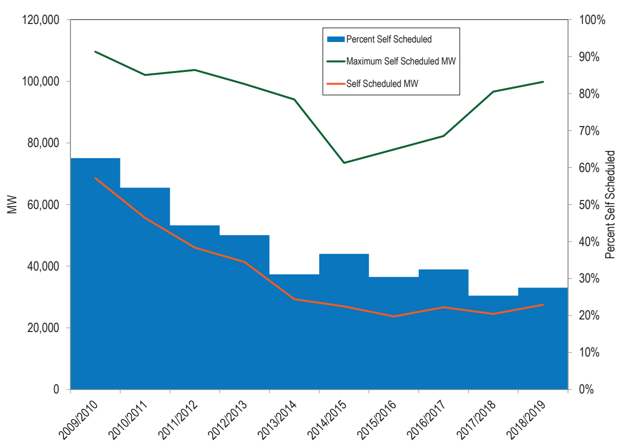


Table 13-15 shows the relationship between source and sink node types in the cleared buy and self scheduled bids for the 2018/2019 Annual FTR Auction.

Generator to generator FTRs comprise 48.3 percent of all cleared FTR buy and self scheduled bids. It is not clear why such a large proportion of generator to generator FTRs exist.

The MMU recommends PJM examine the source and sink node combinations available in the FTR market.

Table 13-15 Annual auction FTR node type matrix: 2018/2019

	Sink Type							
Source Type	Aggregate	EHV Aggregate	Generator	Hub	Interface	Load	Residual Metered Aggregate	Zone
Aggregate	10,659.1	34.5	37,124.4	2,368.1	432.9	2,659.2	1,168.2	3,080.0
EHV Aggregate	0.6	0.0	100.5	0.5	0.0	16.4	0.0	0.0
Generator	63,064.8	998.5	297,226.6	21,624.3	6,039.9	19,943.6	27,300.8	44,726.2
Hub	1,559.3	0.0	2,705.9	4,271.8	16.0	344.2	2,108.0	19,920.7
Interface	137.6	2.0	2,181.4	823.9	123.2	115.0	552.9	515.3
Load	3,331.6	0.0	12,175.1	446.5	347.5	1,456.7	226.0	686.1
Residual Metered Aggregate	75.2	0.0	1,216.7	110.1	3.1	21.6	38.4	171.3
Zone	3,988.9	0.0	4,490.0	3,004.5	339.4	550.1	2,100.1	6,381.0

Monthly Balancing of Planning Period Auctions

Table 13-16 provides the monthly balance of planning period FTR auction market volume for the entire 2017/2018 and first seven months of the 2018/2019 planning periods. There were 10,307,805 MW of FTR obligation buy bids and 4,486,913 MW of FTR obligation sell offers for all bidding periods in the first seven months of the 2018/2019 planning period. The monthly balance of planning period FTR auction cleared 1,894,328 MW (18.4 percent) of FTR obligation buy bids and 866,096 MW (19.3 percent) of FTR obligation sell offers.

There were 3,796,677 MW of FTR option buy bids and 1,218,696 MW of FTR option sell offers for all bidding periods in the Monthly Balance of Planning Period FTR Auctions for the first seven months of the 2018/2019 planning period. The monthly auctions cleared 144,937 MW (3.8 percent) of FTR option buy bids, and 315,030 MW (25.8 percent) of FTR option sell offers.

Table 13-16 Monthly Balance of Planning Period FTR Auction market volume: 2018

Monthly Auction	Type	Trade Type	Bid and Requested Count	Bid and Requested Volume (MW)	Cleared Volume (MW)	Cleared Volume	Uncleared Volume (MW)	Uncleared Volume
Jan-18	Obligations	Buy bids	253,844	1,130,000	170,619	15.1%	959,380	84.9%
		Sell offers	147,997	271,237	80,121	29.5%	191,116	70.5%
	Options	Buy bids	2,577	364,041	3,301	0.9%	360,740	99.1%
		Sell offers	2,486	21,322	6,036	28.3%	15,286	71.7%
Feb-18	Obligations	Buy bids	244,131	1,060,731	137,853	13.0%	922,878	87.0%
		Sell offers	138,358	217,484	65,466	30.1%	152,018	69.9%
	Options	Buy bids	4,215	317,934	3,596	1.1%	314,338	98.9%
		Sell offers	3,986	28,592	6,650	23.3%	21,942	76.7%
Mar-18	Obligations	Buy bids	227,221	1,011,651	152,521	15.1%	859,130	84.9%
		Sell offers	155,770	230,567	79,273	34.4%	151,294	65.6%
	Options	Buy bids	3,425	279,679	8,849	3.2%	270,831	96.8%
		Sell offers	3,956	33,102	8,441	25.5%	24,661	74.5%
Apr-18	Obligations	Buy bids	184,899	689,988	116,534	16.9%	573,454	83.1%
		Sell offers	111,132	214,221	63,874	29.8%	150,347	70.2%
	Options	Buy bids	1,910	167,957	3,703	2.2%	164,253	97.8%
		Sell offers	2,297	27,710	11,539	41.6%	16,171	58.4%
May-18	Obligations	Buy bids	105,469	411,602	75,600	18.4%	336,002	81.6%
		Sell offers	64,587	116,570	31,971	27.4%	84,598	72.6%
	Options	Buy bids	1,081	73,667	1,689	2.3%	71,978	97.7%
		Sell offers	1,086	12,776	4,342	34.0%	8,434	66.0%
Jun-18	Obligations	Buy bids	353,520	1,399,087	262,619	18.8%	1,136,468	81.2%
		Sell offers	185,746	372,831	93,638	25.1%	279,193	74.9%
	Options	Buy bids	10,376	683,108	32,370	4.7%	650,738	95.3%
		Sell offers	28,579	220,298	47,047	21.4%	173,251	78.6%
Jul-18	Obligations	Buy bids	371,266	1,465,317	257,293	17.6%	1,208,024	82.4%
		Sell offers	160,258	319,862	81,845	25.6%	238,017	74.4%
	Options	Buy bids	9,564	778,061	26,669	3.4%	751,392	96.6%
		Sell offers	17,533	163,171	47,776	29.3%	115,395	70.7%
Aug-18	Obligations	Buy bids	426,897	1,604,185	247,266	15.4%	1,356,919	84.6%
		Sell offers	331,772	1,020,958	240,414	23.5%	780,544	76.5%
	Options	Buy bids	7,912	755,697	20,251	2.7%	735,445	97.3%
		Sell offers	25,208	215,868	54,674	25.3%	161,194	74.7%
Sep-18	Obligations	Buy bids	402,657	1,605,704	316,407	19.7%	1,289,297	80.3%
		Sell offers	326,489	836,187	141,189	16.9%	694,997	83.1%
	Options	Buy bids	9,725	1,151,926	23,594	2.0%	1,128,332	98.0%
		Sell offers	18,772	171,287	45,394	26.5%	125,893	73.5%
Oct-18	Obligations	Buy bids	390,004	1,452,463	282,064	19.4%	1,170,399	80.6%
		Sell offers	292,457	680,808	116,613	17.1%	564,195	82.9%
	Options	Buy bids	7,948	146,652	13,695	9.3%	132,957	90.7%
		Sell offers	18,774	159,638	40,560	25.4%	119,078	74.6%
Nov-18	Obligations	Buy bids	385,335	1,438,174	271,041	18.8%	1,167,133	81.2%
		Sell offers	224,012	548,221	79,438	14.5%	468,783	85.5%
	Options	Buy bids	9,599	154,512	14,829	9.6%	139,683	90.4%
		Sell offers	15,036	135,826	33,988	25.0%	101,839	75.0%
Dec-18	Obligations	Buy bids	366,722	1,342,875	257,638	19.2%	1,085,237	80.8%
		Sell offers	294,657	708,047	112,957	16.0%	595,090	84.0%
	Options	Buy bids	9,518	126,721	13,528	10.7%	113,193	89.3%
		Sell offers	17,015	152,608	45,591	29.9%	107,017	70.1%
2017/2018*	Obligations	Buy bids	390,004	1,452,463	282,064	19.4%	1,170,399	80.6%
		Sell offers	292,457	680,808	116,613	17.1%	564,195	82.9%
	Options	Buy bids	7,948	146,652	13,695	9.3%	132,957	90.7%
		Sell offers	18,774	159,638	40,560	25.4%	119,078	74.6%
2018/2019**	Obligations	Buy bids	2,696,401	10,307,805	1,894,328	18.4%	8,413,477	81.6%
		Sell offers	1,815,391	4,486,913	866,096	19.3%	3,620,818	80.7%
	Options	Buy bids	64,642	3,796,677	144,937	3.8%	3,651,740	96.2%
		Sell offers	140,917	1,218,696	315,030	25.8%	903,666	74.2%

* Shows twelve months for 2017/2018 ** Shows seven months for 2018/2019

Table 13-17 presents the buy bid, bid and cleared volume of the Monthly Balance of Planning Period FTR Auction, and the effective periods for the volume. The average monthly cleared volume for 2018 was 226,127.6 MW. The average monthly cleared volume for 2017 was 216,931.5 MW.

Table 13-17 Monthly Balance of Planning Period FTR Auction buy bid, bid and cleared volume (MW per period): 2018

Monthly Auction	MW Type	Prompt Month	Second Month	Third Month	Q1	Q2	Q3	Q4	Total
Jan-18	Bid	643,771	320,172	234,141				295,956	1,494,040
	Cleared	99,983	37,722	11,515				24,700	173,920
Feb-18	Bid	636,456	268,377	248,032				225,800	1,378,665
	Cleared	84,107	27,386	17,142				12,815	141,449
Mar-18	Bid	583,003	284,088	286,663				137,577	1,291,330
	Cleared	86,588	34,278	25,156				15,349	161,370
Apr-18	Bid	560,527	297,417						857,945
	Cleared	86,446	33,791						120,237
May-18	Bid	485,269							485,269
	Cleared	77,289							77,289
Jun-18	Bid	493,511	316,759	312,871		304,002	331,832	323,220	2,082,195
	Cleared	111,379	44,907	42,084		33,440	32,271	30,907	294,989
Jul-18	Bid	642,046	358,529	267,013		302,135	336,789	336,866	2,243,378
	Cleared	124,511	48,679	17,228		30,442	30,677	32,425	283,962
Aug-18	Bid	619,148	301,314	261,213		316,021	429,661	432,525	2,359,881
	Cleared	137,642	33,638	21,751		14,466	29,997	30,023	267,518
Sep-18	Bid	918,169	452,148	436,399			484,170	466,746	2,757,630
	Cleared	169,735	57,284	36,550			42,429	34,003	340,002
Oct-18	Bid	695,122	256,884	186,145			225,476	235,487	1,599,115
	Cleared	165,290	48,731	16,942			33,182	31,614	295,760
Nov-18	Bid	666,224	234,883	220,335			197,568	273,676	1,592,686
	Cleared	149,792	39,352	26,479			27,453	42,792	285,869
Dec-18	Bid	671,802	277,693	271,686				248,415	1,469,596
	Cleared	141,206	50,133	42,639				37,188	271,166

Figure 13-5 shows the FTR bid, cleared and net bid volume from June 2003 through December 2018 for Long Term, Annual and Monthly Balance of Planning Period Auctions.[41] Cleared volume includes FTR buy and sell offers that were accepted. The net bid volume includes the total buy, sell and self scheduled offers, counting sell offers as a negative volume. The bid volume is the total of all bid and self scheduled offers, excluding sell offers. Volume in August 2018 was negative due to the liquidation of the GreenHat FTR portfolio, which resulted in a large quantity of FTRs selling in the monthly auction.

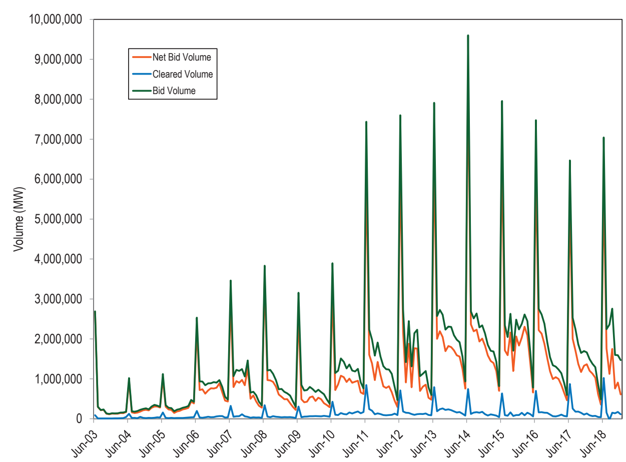
Secondary Bilateral Market

Table 13-18 provides the secondary bilateral FTR market volume for the entire 2017/2018 and the first seven months of the 2018/2019 planning periods.

Table 13-18 Secondary bilateral FTR market volume: 2017/2018 and 2018/2019[40]

Planning Period	Type	Class Type	Volume (MW)
2017/2018	Obligation	24-Hour	167.4
		On Peak	8,630.0
		Off Peak	6,755.4
		Total	15,552.8
	Option	24-Hour	5.8
		On Peak	0.0
		Off Peak	0.0
		Total	5.8
2018/2019	Obligation	24-Hour	2,782.1
		On Peak	16,221.8
		Off Peak	15,759.8
		Total	34,763.7
	Option	24-Hour	0.0
		On Peak	0.0
		Off Peak	0.0
		Total	0.0

Figure 13-5 Long Term, Annual and Monthly FTR Auction bid and cleared volume: June 2003 through December 2018

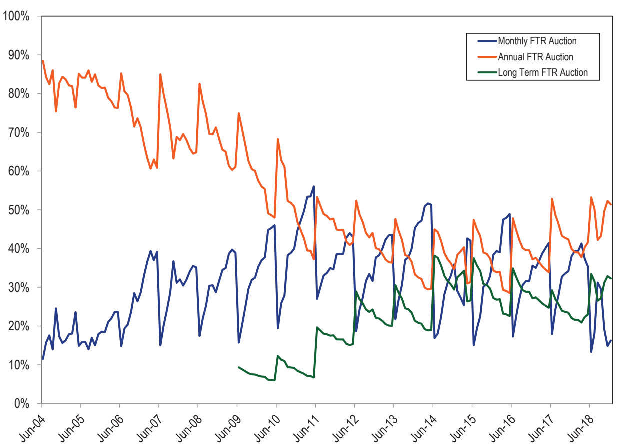


40 The 2017/2018 planning period covers bilateral FTRs that are effective for any time between June 1, 2017 through May 31, 2018, which originally had been purchased in a Long Term FTR Auction, Annual FTR Auction or Monthly Balance of Planning Period FTR Auction.

41 The data for this table are available in *2018 State of the Market Report for PJM*, Volume 2, Appendix H, FTR Volumes.

Figure 13-6 shows cleared auction volumes by auction type as a percent of the total FTR cleared volume by calendar months for June 2004 through December 2018, by type of auction. FTR volumes are included in the calendar month they are effective, with long term and annual FTR auction volume spread equally to each month in the relevant planning period. This figure shows the share of FTRs purchased in each auction type by month. Over the course of any planning period an increasing number of Monthly Balance of Planning Period FTRs are purchased, making them a greater percent of total FTRs. When the Annual FTR Auction occurs, FTRs purchased in any previous Monthly Balance of Planning Period Auction, other than the current June auction, are no longer in effect, so there is a reduction in their share of total FTRs with a corresponding increase in the share of Annual FTRs.

Figure 13-6 Cleared auction volume (MW) as a percent of total FTR cleared volume by calendar month: June 2004 through December 2018



Price

Table 13-19 shows the cleared, weighted-average prices by trade type, FTR direction, period type and class type for the 2018/2021 Long Term FTR Auction. Only FTR obligation products (no options) are available in the Long Term FTR Auctions. In this auction, weighted average buy bid counter flow and prevailing flow FTR prices were -$0.41 and $0.44, compared to -$0.42 and $0.41 from the 2017/2020 Long Term FTR Auction. Weighted average sell bid counter flow and prevailing flow FTR prices were -$0.32 and $0.35, compared to -$0.43 for counter flow FTRs and $0.44 for prevailing flow FTRs.

Table 13-19 Long Term FTR Auction weighted-average cleared prices (Dollars per MW): 2018/2021

			Class Type			
Trade Type	FTR Direction	Period Type	24-Hour	On Peak	Off Peak	All
Buy bids	Counter Flow	Year 1	($1.05)	($0.31)	($0.53)	($0.44)
		Year 2	($0.96)	($0.30)	($0.53)	($0.42)
		Year 3	($0.77)	($0.22)	($0.45)	($0.34)
		Year All	NA	($0.07)	($0.24)	($0.12)
		Total	($0.98)	($0.28)	($0.51)	($0.41)
	Prevailing Flow	Year 1	$0.84	$0.33	$0.56	$0.47
		Year 2	$0.54	$0.33	$0.57	$0.45
		Year 3	$0.79	$0.24	$0.44	$0.36
		Year All	NA	$0.01	$0.01	$0.01
		Total	$0.73	$0.31	$0.54	$0.44
	Total		$0.14	$0.02	$0.04	$0.03
Sell offers	Counter Flow	Year 1	($0.11)	($0.26)	($0.44)	($0.34)
		Year 2	NA	($0.26)	($0.28)	($0.27)
		Year 3	NA	($0.25)	($0.28)	($0.27)
		Year All	NA	NA	NA	NA
		Total	($0.11)	($0.26)	($0.40)	($0.32)
	Prevailing Flow	Year 1	$0.59	$0.25	$0.43	$0.34
		Year 2	$0.27	$0.26	$0.46	$0.35
		Year 3	NA	$0.37	$0.65	$0.48
		Year All	NA	NA	NA	NA
		Total	$0.44	$0.26	$0.45	$0.35
	Total		$0.38	$0.08	$0.17	$0.12

Table 13-20 shows the weighted-average cleared buy bid prices by trade type, FTR product, FTR direction and class type for the Annual FTR Auction for the 2018/2019 planning period. The weighted-average cleared buy bid price in the 2018/2019 Annual FTR Auction was $0.29 per MW, down from $0.24 per MW in the 2017/2018 planning period.

Table 13-20 Annual FTR Auction weighted-average cleared prices (Dollars per MW): 2017/2018

			Class Type			
Trade Type	Type	FTR Direction	24-Hour	On Peak	Off Peak	All
Buy bids	Obligations	Counter Flow	($0.53)	($0.41)	($0.26)	($0.34)
		Prevailing Flow	$1.29	$0.65	$0.37	$0.59
		Total	$0.98	$0.23	$0.11	$0.23
	Options	Counter Flow	$0.00	$0.00	$0.00	$0.00
		Prevailing Flow	$0.10	$0.36	$0.21	$0.28
		Total	$0.10	$0.36	$0.21	$0.28
Self-scheduled bids	Obligations	Counter Flow	($0.10)	NA	NA	($0.10)
		Prevailing Flow	$0.91	NA	NA	$0.91
		Total	$0.82	NA	NA	$0.82
Buy and self-scheduled bids	Obligations	Counter Flow	($0.37)	($0.41)	($0.26)	($0.33)
		Prevailing Flow	$1.07	$0.65	$0.37	$0.64
		Total	$0.89	$0.23	$0.11	$0.29
	Options	Counter Flow	$0.00	$0.00	$0.00	$0.00
		Prevailing Flow	$0.10	$0.36	$0.21	$0.28
		Total	$0.10	$0.36	$0.21	$0.28
Sell offers	Obligations	Counter Flow	($0.87)	($0.51)	($0.29)	($0.41)
		Prevailing Flow	$1.07	$0.52	$0.28	$0.41
		Total	$0.05	$0.07	$0.02	$0.05
	Options	Counter Flow	NA	NA	NA	NA
		Prevailing Flow	$0.00	$0.27	$0.22	$0.24
		Total	$0.00	$0.27	$0.22	$0.24

Table 13-21 shows the cleared buy bid volume, cleared buy bid revenue and cleared revenue/cleared MW for the six latest planning periods. In the 2014/2015 planning period the $/MW increased significantly from the 2013/2014 planning period due to PJM's decisions to limit capacity through conservative modeling. In the 2017/2018 Annual FTR Auction, the $/MW decreased to lower than 2013/2014 levels, due in part to the partial relaxation of PJM's conservative modeling practices due to the reassignment of balancing congestion and M2M payments to load and exports. This reduction continued into the 2018/2019 planning period. The reassignment of balancing congestion and M2M payments to load did not increase the per MW value of ARRs.

Table 13-21 Cleared volume, revenue and $/MW: 2012/2013 through 2018/2019 Annual FTR Auction

	Cleared Buy Bid Volume	Percent Cleared	Buy Bid Revenue	Buy Bid Revenue ($/MW)
2012/2013	371,295	14.5%	$627.3	$1,689
2013/2014	420,489	12.8%	$567.6	$1,350
2014/2015	365,843	11.2%	$789.7	$2,159
2015/2016	378,328	15.4%	$948.6	$2,507
2016/2017	420,198	16.2%	$918.0	$2,185
2017/2018	513,263	22.3%	$555.2	$1,082
2018/2019	587,775	20.4%	$833.4	$1,418

Table 13-22 shows the weighted average cleared buy bid price in the Monthly Balance of Planning Period FTR Auctions by bidding period for January through December 2018. For example, for the January Monthly Balance of Planning Period FTR Auction, the current month column is January, the second month column is February and the third month column is March. Quarters 1 through 4 are represented in the Q1, Q2, Q3 and Q4 columns. The total column represents all of the activity within the January Monthly Balance of Planning Period FTR Auction.

The cleared weighted-average price paid in the Monthly Balance of Planning Period FTR Auctions for January through December 2018 was $0.20 per MW, up from $0.11 per MW in the same time last year, a 81.8 percent increase in FTR prices. The cleared weighted-average price for the current planning period was $0.13, up 8.3 percent from $0.12 for the previous planning period.

Table 13-22 Monthly Balance of Planning Period FTR Auction cleared, weighted-average, buy bid price per period (Dollars per MW): 2018

Monthly Auction	Prompt Month	Second Month	Third Month	Q1	Q2	Q3	Q4	Total
Jan-18	$0.07	$0.08	$0.13				$0.18	$0.11
Feb-18	$0.21	$0.16	$0.11				$0.18	$0.18
Mar-18	$0.14	$0.20	$0.22				$0.01	$0.13
Apr-18	$0.26	$0.38						$0.29
May-18	$0.20							$0.20
Jun-18	$0.19	$0.22	$0.22		$0.23	$0.27	$0.20	$0.22
Jul-18	$0.18	$0.24	($0.03)		$0.23	$0.26	$0.13	$0.19
Aug-18	($0.05)	$0.22	$0.21		$0.29	$0.26	$0.22	$0.15
Sep-18	$0.14	$0.17	$0.15			$0.31	$0.13	$0.19
Oct-18	$0.16	$0.19	($0.02)			$0.41	$0.24	$0.23
Nov-18	$0.14	$0.16	$0.31			$0.28	$0.14	$0.18
Dec-18	$0.25	$0.58	$0.57			$0.00	$0.15	$0.30

Profitability

FTR profitability is the difference between the revenue received for an FTR and the cost of the FTR for entities that purchase FTRs. For a prevailing flow FTR, the FTR credits are the actual revenue that an FTR holder receives and the auction price is the cost. For a counter flow FTR, the auction price is the revenue that an FTR holder is paid and the FTR credits are the cost to the FTR holder, which the FTR holder must pay. ARR holders that self schedule FTRs do not receive a profit on the transaction and are trading rights to congestion revenues for a fixed payment.

The fact that FTRs have been consistently profitable for financial entities regardless of the payout ratio raises questions about the competitiveness of the market. Accounting for direct profitability and the distribution of surplus congestion revenue, FTR purchases by financial entities were not profitable in 2012/2013 and were profitable in every planning year from 2013/2014 through 2016/2017, and were profitable if summed over the entire period (Table 13-25). It is not clear, in a competitive market, why FTR purchases by financial entities remain persistently profitable. In a competitive market, it would be expected that profits would be competed to zero.

Table 13-23 lists FTR profits by organization type and FTR direction for the first seven months of the 2018/2019 planning period. Some participants classified as physical, such as a company that holds one generator, are not eligible for ARRs but do have a physical presence on the PJM system are classified in the physical category. FTR profits are the sum of the daily FTR target allocations, adjusted by the payout ratio minus the daily FTR auction costs for each FTR (not self scheduled) held by an organization. Self scheduled FTRs can have a negative value, depending on the congestion on the FTR path. The FTR target allocation is equal to the product of the FTR MW and congestion price differences between sink and source in the Day-Ahead Energy Market. The FTR credits do not include after the fact adjustments which are very small and do not occur in every month. The FTR credits also do not include any excess congestion revenue distributions made at the end of the planning period. The daily FTR auction costs are the product of the FTR MW and the auction price divided by the time period of the FTR in days. Self scheduled FTRs have zero cost. FTR profitability is the difference between the revenue received for an FTR and the cost of that FTR, not including self scheduled FTRs . Self scheduled FTRs represent a return of congestion revenue to ARR holders, and are not profits. In the first seven months of the 2018/2019 planning period, companies made profits of $217.2 million. ARR holders who self scheduled FTRs received $91.3 million in congestion revenues. Revenues from self scheduled FTRs are a return of congestion to the load that paid the congestion rather than profits.

Table 13-23 FTR profits and revenues by organization type and FTR direction: 2017/2018

	FTR Direction				
Organization Type	Prevailing Flow Profit	Self Scheduled Prevailing Flow Revenue Returned	Counter Flow Profit	Self Scheduled Counter Flow Revenue Returned	All
Financial	$16,767,068	$0	$76,897,508	$0	$93,664,575
Physical	($10,287,976)	$89,596,126	$42,583,579	$1,664,863	$123,556,592
Total	$6,479,092	$89,596,126	$119,481,087	$1,664,863	$217,221,168

Table 13-24 lists the monthly FTR profits for the 2017/2018 and the first seven months of the 2018/2019 planning periods by organization type. FTR revenues for ARR holders who self schedule are not included. FTR profits for ARR holders who purchase FTRs in auctions are included.

Table 13-24 Monthly FTR profits by organization type: 2017/2018 and 2018/2019

	Organization Type		
Month	Physical	Financial	Total
Jun-17	$764,708	$14,019,198	$14,783,906
Jul-17	($2,987,829)	$7,306,611	$4,318,783
Aug-17	($3,234,012)	$2,414,244	($819,767)
Sep-17	$2,168,231	$22,644,485	$24,812,716
Oct-17	$777,230	$14,400,509	$15,177,739
Nov-17	$2,350,616	$3,244,972	$5,595,588
Dec-17	$820,082	$23,681,735	$24,501,817
Jan-18	$32,871,784	$103,179,520	$136,051,304
Feb-18	$317,895	($2,047,899)	($1,730,004)
Mar-18	$8,526,358	$13,327,501	$21,853,859
Apr-18	$574,714	$7,467,985	$8,042,698
May-18	$10,386,785	$36,679,052	$47,065,837
	Summary for Planning Period 2017/2018		
Total	$53,336,562	$246,317,915	$299,654,477
Jun-18	$8,959,001	$16,374,714	$25,333,715
Jul-18	($7,329,905)	$8,826,482	$1,496,576
Aug-18	($2,093,482)	$6,880,524	$4,787,043
Sep-18	$19,875,921	$16,799,058	$36,674,979
Oct-18	$9,065,717	$20,328,429	$29,394,146
Nov-18	$7,892,354	$8,051,851	$15,944,205
Dec-18	($4,074,003)	$16,403,516	$12,329,514
	Summary for Planning Period 2018/2019		
Total	$32,295,603	$93,664,575	$125,960,179

Table 13-25 lists the historical profits by calendar year by organization type beginning in the 2012/2013 planning period, excluding revenue to self scheduled FTRs for physical participants. The profits include any end of planning period surplus distribution or uplift, where applicable, that will impact total profitability. The surplus or uplift is distributed prorata based on positive target allocations. The surplus row indicates the surplus congestion revenue collected from the FTR market through the planning period. When positive, it is a payout to rights holders distributed pro-rata, which includes surplus ARR auction revenue and surplus day-ahead congestion revenue. When negative, it is a payment made to the FTR market, pro-rata, by all FTR holders to meet revenue adequacy.

Table 13-25 FTR profits by organization type: 2012/2013 through 2018/2019

		2012/2013	2013/2014	2014/2015	2015/2016	2016/2017	2017/2018	2018/2019*
Financial	Profit	$63,457,511	$557,583,317	$236,692,290	$41,264,165	($13,519,824)	$246,317,915	$93,664,575
	Surplus	($80,450,357)	($256,820,253)	$44,410,625	$11,897,525	$20,968,663	$147,413,287	
	Total	($16,992,846)	$300,763,064	$281,102,915	$53,161,690	$7,448,839	$393,731,202	$93,664,575
Physical	Profit	($65,702,875)	$401,144,350	$160,694,399	$22,585,629	($112,955,478)	$88,426,464	$32,295,603
	Surplus	($83,332,665)	($104,947,376)	$14,485,066	$5,072,985	$10,533,444	$67,512,070	
	Total	($149,035,540)	$296,196,975	$175,179,465	$27,658,614	($102,422,034)	$155,938,535	$32,295,603
Total		($166,028,386)	$596,960,039	$456,282,380	$80,820,304	($94,973,195)	$549,669,736	$125,960,179

* Seven months of the 2018/2019 planning period

Revenue

Long Term FTR Auction Revenue

Table 13-26 shows the long term FTR auction revenue data by trade type, FTR direction, period type and class type. The 2018/2021 Long Term FTR Auction netted $29.6 million in revenue, $2.9 million more than the previous Long Term FTR Auction. Buyers paid $52.2 million and sellers received $22.6 million, up $3.8 million and $0.9 million over the previous Long Term FTR Auction.

Table 13-26 Long Term FTR Auction Revenue: 2018/2021

			Class Type			
Trade Type	FTR Direction	Period Type	24-Hour	On Peak	Off Peak	All
Buy bids	Counter Flow	Year 1	($16,014,942)	($90,483,112)	($59,016,919)	($165,514,973)
		Year 2	($9,474,029)	($56,290,521)	($39,156,134)	($104,920,683)
		Year 3	($3,164,672)	($20,161,791)	($12,798,173)	($36,124,637)
		Year All	$0	($1,562,132)	($948,434)	($2,510,566)
		Total	($28,653,643)	($168,497,557)	($111,919,660)	($309,070,859)
	Prevailing Flow	Year 1	$23,490,163	$102,541,301	$64,783,731	$190,815,195
		Year 2	$9,924,662	$67,678,319	$46,229,508	$123,832,489
		Year 3	$6,610,577	$24,071,926	$15,852,953	$46,535,457
		Year All	$0	$17,585	$31,960	$49,545
		Total	$40,025,402	$194,309,131	$126,898,152	$361,232,685
	Total		$11,371,759	$25,811,574	$14,978,492	$52,161,826
Sell offers	Counter Flow	Year 1	($5,032)	($8,708,653)	($6,116,001)	($14,829,686)
		Year 2	$0	($2,195,991)	($3,106,910)	($5,302,901)
		Year 3	0	($99,165)	($72,669)	($171,834)
		Year All	NA	NA	NA	NA
		Total	($5,032)	($11,003,810)	($9,295,579)	($20,304,421)
	Prevailing Flow	Year 1	$123,386	$16,832,527	$11,038,243	$27,994,155
		Year 2	$52,545	$7,811,807	$5,276,957	$13,141,309
		Year 3	0	$942,960	$821,353	$1,764,314
		Year All	NA	NA	NA	NA
		Total	$175,931	$25,587,294	$17,136,553	$42,899,778
	Total		$170,899	$14,583,484	$7,840,974	$22,595,357
Total			$11,200,860	$11,228,090	$7,137,519	$29,566,469

Annual FTR Auction Revenue

Table 13-27 shows the Annual FTR Auction revenue by trade type, type, FTR direction and class type. The Annual FTR Auction for the 2018/2019 planning period generated $822.6 million, up 51.7 percent from $542.2 million in the 2017/2018 planning period, and down 9.5 percent from $909.0 million in the 2016/2017 planning period. Counter flow FTR holders received $274.8 million, up 17.9 percent from the previous planning period and prevailing flow FTR holders paid $1,097.4 million, up 43.4 percent from the previous planning period.

Table 13-27 Annual FTR auction revenue: 2018/2019

			Class Type			
Trade Type	Type	FTR Direction	24-Hour	On Peak	Off Peak	All
Buy bids	Obligations	Counter Flow	($18,084,316)	($172,006,373)	($121,204,230)	($311,294,919)
		Prevailing Flow	$208,382,599	$408,672,916	$248,080,676	$865,136,191
		Total	$190,298,282	$236,666,543	$126,876,446	$553,841,272
	Options	Counter Flow	$0	$0	$0	$0
		Prevailing Flow	$2,311,548	$50,740,739	$28,755,261	$81,807,547
		Total	$2,311,548	$50,740,739	$28,755,261	$81,807,547
	Total	Counter Flow	($18,084,316)	($172,006,373)	($121,204,230)	($311,294,919)
		Prevailing Flow	$210,694,147	$459,413,655	$276,835,937	$946,943,738
		Total	$192,609,830	$287,407,282	$155,631,707	$635,648,819
Self-scheduled bids	Obligations	Counter Flow	($2,066,090)	NA	NA	($2,066,090)
		Prevailing Flow	$199,834,942	NA	NA	$199,834,942
		Total	$197,768,852	NA	NA	$197,768,852
Buy and self-scheduled bids	Obligations	Counter Flow	($20,150,407)	($172,006,373)	($121,204,230)	($313,361,009)
		Prevailing Flow	$408,217,541	$408,672,916	$248,080,676	$1,064,971,133
		Total	$388,067,134	$236,666,543	$126,876,446	$751,610,124
	Options	Counter Flow	$0	$0	$0	$0
		Prevailing Flow	$2,311,548	$50,740,739	$28,755,261	$81,807,547
		Total	$2,311,548	$50,740,739	$28,755,261	$81,807,547
	Total	Counter Flow	($20,150,407)	($172,006,373)	($121,204,230)	($313,361,009)
		Prevailing Flow	$410,529,089	$459,413,655	$276,835,937	$1,146,778,681
		Total	$390,378,682	$287,407,282	$155,631,707	$833,417,671
Sell offers	Obligations	Counter Flow	($3,352,510)	($21,072,998)	($14,100,676)	($38,526,185)
		Prevailing Flow	$3,710,307	$28,219,047	$16,835,074	$48,764,428
		Total	$357,796	$7,146,049	$2,734,398	$10,238,243
	Options	Counter Flow	$0	$0	$0	$0
		Prevailing Flow	$0	$329,174	$259,005	$588,179
		Total	$0	$329,174	$259,005	$588,179
	Total	Counter Flow	($3,352,510)	($21,072,998)	($14,100,676)	($38,526,185)
		Prevailing Flow	$3,710,307	$28,548,222	$17,094,079	$49,352,607
		Total	$357,796	$7,475,224	$2,993,402	$10,826,422
Total			$390,020,886	$279,932,058	$152,638,305	$822,591,249

The total net of all buy and sell offers in the Annual FTR Auction, not including self scheduled FTRs, was $393.5 million for the 2017/2018 planning period and $624.8 million for the 2018/2019 planning period, a 58.8 percent increase in revenue. The total buy bids were 488,734.1 MW for the 2017/2018 planning period and 587,775.4 MW for the 2018/2019 planning period. The revenue of FTRs per cleared MW increased from $805.14 for the 2017/2018 planning period to $1,062.99 for the 2018/2019 planning period, a 32.0 percent increase. The per MW revenue of FTRs in the 2016/2017 planning period was $1,564.83. Load receives lower ARR revenues in addition to the fact that load has to bear 100 percent of the costs of balancing congestion.

FTRs sold in Long Term FTR Auctions are sold at a substantial discount to the same FTR sold in Annual FTR Auctions. Table 13-28 shows the increase in total auction revenue that would have resulted for the 2014/2015 through 2018/2019 planning periods if long term FTRs were sold at annual auction clearing prices. This difference provides a good estimate of the value of the transmission capability made available in the Long Term FTR Auction that is not made available to ARR holders. This capability should be made available to ARR holders in the Annual FTR Auction where it is the most valuable.

Table 13-28 Estimated additional Long Term FTR Auction revenue at Annual FTR Auction prices

	Long Term FTR Product				
Planning Period	YR3	YR2	YR1	YRALL	Total Difference
2014/2015	$59,598,642	$30,284,173	$52,030,909	$926,989	$142,840,713
2015/2016	$67,896,588	$40,975,278	$9,936,078	$303,082	$119,111,026
2016/2017	$42,378,048	$3,854,373	$11,055,824	$1,079,901	$58,368,147
2017/2018	$6,134,076	($1,841,715)	$12,396,817	$227,524	$16,916,702
2018/2019	$7,872,604	$2,926,457	$13,480,353	($111,226)	$24,168,189
Total	$183,879,959	$76,198,567	$98,899,981	$2,426,270	$361,404,776

Monthly Balance of Planning Period FTR Auction Revenue

Table 13-29 shows monthly balance of planning period FTR auction revenue by trade type, type and class type for January through December 2018. The Monthly Balance of Planning Period FTR Auctions for the first seven months of the 2018/2019 planning period netted $47.3 million in revenue, the difference between buyers paying $240.6 million and sellers receiving $193.3 million. For the entire 2017/2018 planning period, the Monthly Balance of Planning Period FTR Auctions netted $40.3 million in revenue with buyers paying $182.0 million and sellers receiving $141.7 million.

Table 13-29 Monthly Balance of Planning Period FTR Auction revenue: 2018

			Class Type			
Monthly Auction	Type	Trade Type	24-Hour	On Peak	Off Peak	All
Jan-18	Obligations	Buy bids	$1,136,987	$4,908,283	$2,908,181	$8,953,452
		Sell offers	$122,629	$2,557,292	$1,382,114	$4,062,036
	Options	Buy bids	$78,668	$103,035	$214,442	$396,145
		Sell offers	$6,014	$745,064	$596,327	$1,347,404
Feb-18	Obligations	Buy bids	$918,113	$5,745,959	$3,621,458	$10,285,530
		Sell offers	$531,850	$2,330,156	$894,900	$3,756,907
	Options	Buy bids	$2,970	$354,814	$308,893	$666,677
		Sell offers	$6,876	$1,341,491	$981,125	$2,329,492
Mar-18	Obligations	Buy bids	$324,055	$5,623,191	$2,867,153	$8,814,399
		Sell offers	$431,612	$3,296,743	$1,240,118	$4,968,472
	Options	Buy bids	$376,702	$210,189	$136,034	$722,925
		Sell offers	$4,087	$1,480,291	$888,487	$2,372,865
Apr-18	Obligations	Buy bids	$3,805,239	$5,504,318	$3,731,492	$13,041,049
		Sell offers	$408,182	$5,358,307	$3,765,433	$9,531,922
	Options	Buy bids	$94,966	$176,215	$67,420	$338,601
		Sell offers	$7,408	$1,109,406	$787,821	$1,904,636
May-18	Obligations	Buy bids	$902,453	$3,170,886	$1,522,229	$5,595,568
		Sell offers	$53,493	$2,759,329	$1,487,284	$4,300,105
	Options	Buy bids	$334,208	$75,972	$18,038	$428,217
		Sell offers	$537	$501,559	$260,753	$762,849
Jun-18	Obligations	Buy bids	$9,927,013	$17,356,413	$9,803,845	$37,087,271
		Sell offers	$1,853,241	$11,514,997	$7,024,017	$20,392,255
	Options	Buy bids	$8,711	$2,004,778	$1,528,168	$3,541,658
		Sell offers	$129,482	$5,150,031	$3,048,089	$8,327,602
Jul-18	Obligations	Buy bids	$6,049,810	$16,555,133	$8,358,107	$30,963,049
		Sell offers	$505,883	$11,593,183	$6,664,123	$18,763,189
	Options	Buy bids	$271,397	$1,635,470	$1,634,277	$3,541,144
		Sell offers	$160,246	$5,479,499	$2,709,012	$8,348,757
Aug-18	Obligations	Buy bids	$10,217,455	$8,682,232	$1,368,195	$20,267,881
		Sell offers	$1,431,032	$2,951,842	$595,988	$4,978,862
	Options	Buy bids	$193,697	$1,470,027	$1,186,721	$2,850,445
		Sell offers	$168,206	$6,709,400	$3,356,201	$10,233,807
Sep-18	Obligations	Buy bids	$5,090,821	$16,168,325	$8,266,808	$29,525,954
		Sell offers	$917,228	$12,654,570	$7,068,818	$20,640,616
	Options	Buy bids	$163,963	$2,471,051	$2,287,217	$4,922,231
		Sell offers	$216,038	$4,487,173	$2,854,819	$7,558,030
Oct-18	Obligations	Buy bids	$14,966,414	$12,506,767	$4,906,209	$32,379,390
		Sell offers	$1,507,857	$15,065,734	$8,785,395	$25,358,986
	Options	Buy bids	$3,160	$3,235,941	$2,512,900	$5,752,001
		Sell offers	$115,760	$5,252,963	$2,738,803	$8,107,525
Nov-18	Obligations	Buy bids	$11,694,954	$11,464,584	$3,320,854	$26,480,392
		Sell offers	$576,536	$11,568,998	$6,181,652	$18,327,186
	Options	Buy bids	$302,476	$1,743,662	$1,014,269	$3,060,406
		Sell offers	$113,057	$4,176,283	$2,502,160	$6,791,500
Dec-18	Obligations	Buy bids	$12,994,175	$14,867,879	$7,755,077	$35,617,131
		Sell offers	$964,999	$14,746,115	$10,303,269	$26,014,384
	Options	Buy bids	$1,290,407	$1,799,807	$1,539,023	$4,629,236
		Sell offers	$73,201	$5,899,848	$3,463,654	$9,436,703
2017/2018*	Obligations	Buy bids	$48,624,806	$80,725,915	$45,185,177	$174,535,897
		Sell offers	$3,856,422	$66,996,797	$39,571,417	$110,424,636
	Options	Buy bids	$888,416	$4,051,136	$2,566,754	$7,506,306
		Sell offers	$106,899	$19,516,633	$11,671,850	$31,295,383
	Net Total		$45,549,900	($1,736,379)	($3,491,336)	$40,322,185
2018/2019**	Obligations	Buy bids	$70,940,642	$97,601,332	$43,779,094	$212,321,068
		Sell offers	$7,756,776	$80,095,439	$46,623,263	$134,475,478
	Options	Buy bids	$2,233,811	$14,360,736	$11,702,573	$28,297,121
		Sell offers	$975,989	$37,155,197	$20,672,738	$58,803,924
	Net Total		$64,441,688	($5,288,568)	($11,814,333)	$47,338,787

* Shows Twelve Months ** Shows seven months

FTR Target Allocations

FTR target allocations were examined separately by source and sink contribution. Hourly FTR target allocations were divided into those that were benefits and liabilities and summed by sink and by source. Figure 13-7 shows the 10 largest positive and negative FTR target allocations, summed by sink, for the 2018/2019 planning period. The top 10 sinks that produced financial benefit accounted for 28.5 percent of total positive target allocations with the Western Hub accounting for 6.3 percent of all positive target allocations. The top 10 sinks that created liability accounted for 14.7 percent of total negative target allocations with the PSEG zone accounting for 2.1 percent of all negative target allocations.

Figure 13-7 Ten largest positive and negative FTR target allocations summed by sink: 2018/2019

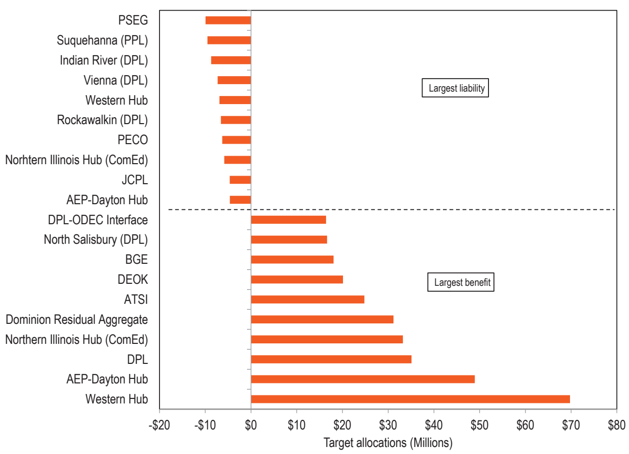
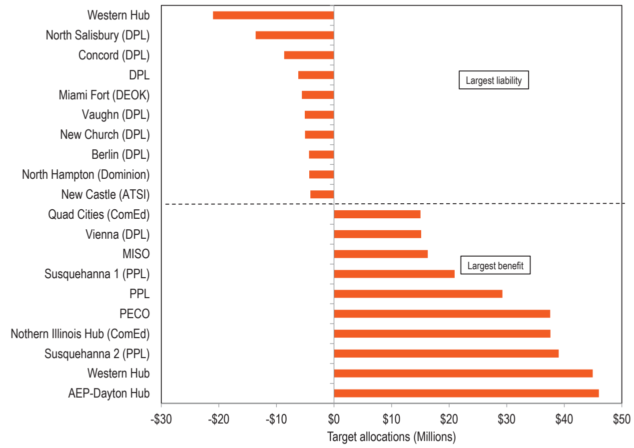


Figure 13-8 shows the 10 largest positive and negative FTR target allocations, summed by source, for the 2018/2019 planning period. The top 10 sources with a positive target allocation accounted for 27.4 percent of total positive target allocations with the AEP-Dayton Hub accounting for 4.2 percent of total positive target allocations. The top 10 sources with a negative target allocation accounted for 16.3 percent of all negative target allocations, with the Western Hub accounting for 4.4 percent.

Figure 13-8 Ten largest positive and negative FTR target allocations summed by source: 2018/2019



Revenue Adequacy

FTR revenue adequacy is not equivalent to the adequacy of ARRs/FTRs as an offset for load against total congestion. FTR revenue adequacy, under current PJM rules, is a narrower concept that compares day-ahead congestion revenue to the sum of the target allocations across the specific paths for which FTRs were purchased. A path specific target allocation is not a guarantee of payment. The adequacy of ARRs/FTRs as an offset for load against total congestion compares ARR and self scheduled FTR revenues, minus balancing congestion and M2M payments, to total congestion on the system.

FTR revenues are primarily comprised of hourly congestion revenue, from the day-ahead market, but also include negative FTR target allocations.[42] Total day-ahead congestion revenues in excess of FTR payments are carried forward from prior months and distributed back from later months within each planning year. For example, in June 2014, $2.9 million in excess congestion revenues were carried forward to fund months later in the planning period with a revenue shortfall. At the end of a planning period, if some months remain not fully funded, an uplift charge is collected at the end of the planning period from any FTR holders during the planning period based on their pro rata share of total net positive FTR target allocations, excluding any charge to FTR holders with a net negative FTR position for the planning year. Before the 2018/2019 planning period, at the end of the planning period, surplus congestion

42 When hourly congestion revenues are negative, it is defined as a net negative congestion hour.

revenue, after paying any monthly shortfalls, was distributed to FTR participants in the same manner that the FTR uplift is applied. From the 2018/2019 planning period onward, at the end of the planning period, surplus congestion revenue is distributed to ARR holders prorata based on their target allocations, after making FTRs revenue adequate, and the FTR uplift continues to be applied to FTR holders. This distribution is an effort to return the congestion to load that is not available to them throughout the planning period. This method does not go far enough in that the long term auction continues to remove capacity that should be available to ARR holders, and that the terms of this distribution do not ensure ARR holders receive all of the surplus revenue.

FTR Revenue Adequacy and Stage 1B/Stage 2 ARR Allocations

A high level of revenue adequacy was primarily a result of PJM's subjective decision to reduce available system capability in FTR auctions for the 2014/2015 through 2016/2017 planning periods. PJM's decision to reduce available system capability was intended to guarantee that FTR target allocations were, on an annual basis, less than congestion. As congestion revenues are unrelated to PJM's decisions about the FTR auction model, the fewer FTRs sold, the higher the probability that congestion would exceed the sum of the FTR target allocations. PJM's decisions included the arbitrary use of higher outage levels and the decision to include additional constraints (closed loop interfaces) both of which reduced system capability in the FTR auction model. PJM's actions led to a significant reduction in the allocation of Stage 1B and Stage 2 ARRs and therefore a reduction in available FTRs.

While PJM's arbitrary decision to increase outages in the ARR allocation and in the Annual FTR Auction reduced FTR revenue inadequacy, it did not address the Stage 1A ARR over allocation issue directly because Stage 1A ARR allocations cannot be prorated. PJM's actions for the 2014/2015 through 2016/2017 planning periods resulted in decreased Stage 1B ARR allocations, decreased Stage 2 ARR allocations and decreased FTR capability. Following the assignment of balancing congestion and M2M payments to load beginning in the 2017/2018 planning period, PJM reduced the number of outages taken in the ARR allocation and in the Annual FTR Auction, increasing ARR allocations and FTR availability. The direct assignment of negative balancing congestion to load increased the congestion revenue available to pay FTR holders.

Surplus Congestion Revenue

Beginning in the 2018/2019 planning period, surplus congestion revenue, including surplus FTR auction revenue, will be distributed to ARR holders in proportion to their ARR target allocations.[43] Surplus FTR auction revenue is the difference between ARR target allocations and the sum of FTR auction revenues. PJM initiated this change to surplus congestion revenue to recognize that any surplus revenue is a result of unallocated system capability that belongs to ARR holders, not FTR holders, who had received this surplus revenue after the creation of ARRs.

Under the new allocation process, at the end of the planning period, any surplus congestion revenue will first go to ARR holders until they are revenue adequate relative to their target allocations if they are not already. The remaining surplus congestion revenue is then applied to cover FTR target allocations, if they are not already. Then at the end of the planning period, any remaining surplus congestion revenue after funding ARRs and FTRs to 100 percent, will go to ARR holders in proportion to their target allocations. While the new allocation process returns the value of some of the unallocated rights to ARR holders, it does not fully recognize that ARR holders own the rights to all congestion revenues.

Figure 13-9 shows the total monthly ARR auction revenue surplus, and its distribution to ARR and FTR holders within a month. Surplus auction revenue is first paid to FTR holders, to meet revenue adequacy for the month. In any month that is not revenue adequate from day-ahead congestion, the surplus auction revenue is used to meet revenue adequacy for FTRs. In months that are revenue inadequate even after the allocation of surplus auction revenue of that month, any remaining inadequacy is funded from surplus revenue from previous or future months within the planning period. At the end of the planning period, any remaining surplus auction

43 163 FERC ¶61,165 (2018).

revenue is distributed, prorata, to ARR holders along with other surplus transmission congestion charges.

The market rules should recognize that ARR holders have the right to all auction revenue, not just the surplus after funding FTRs. The MMU recommends that all FTR auction revenue should be distributed directly to ARR holders on a monthly basis.

Figure 13-9 Monthly surplus ARR revenue to ARR and FTR holders: 2017/2018 through 2018/2019

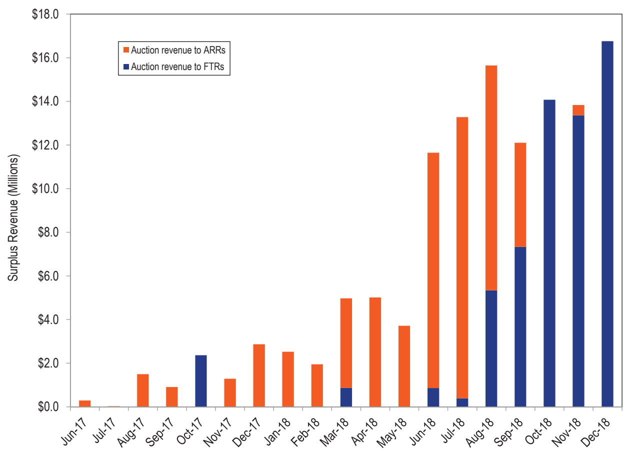


Figure 13-10 shows the monthly auction revenue collected each month from FTR auctions above ARR target allocations from the 2011/2012 through 2018/2019 planning periods.

Beginning with the 2014/2015 planning period, market rules allow PJM to decrease prevailing flow target allocations by clearing counter flow FTRs using FTR auction revenue, without making the opposite prevailing flow FTR available, as long as ARRs remain revenue adequate.[44] The result is to increase FTR funding, but to decrease ARR revenue.

The MMU recommends that all FTR auction revenue be distributed to ARR holders.

44 *See* "PJM Manual 6: Financial Transmission Rights," Rev. 21 (Dec. 6, 2018).

Figure 13-10 Monthly surplus ARR revenue: 2011/2012 through 2018/2019

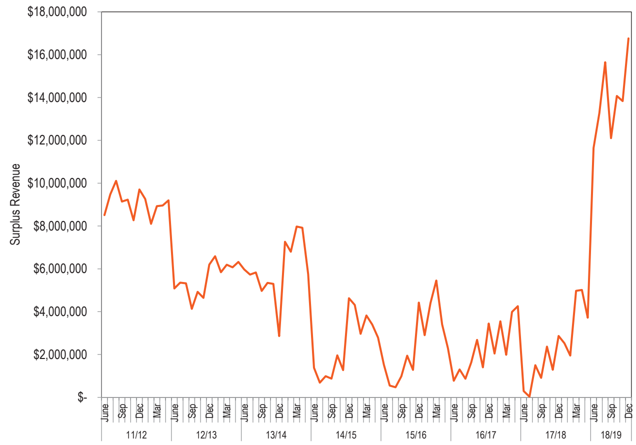


Table 13-30 shows the auction revenue over ARR target allocations, by planning period, for planning periods 2010/2011 through 2018/2019.

Table 13-30 Additional Auction Revenue: 2010/2011 through 2018/2019

Planning Period	Excess Auction Revenue
2010/2011	$29,704,562
2011/2012	$108,874,342
2012/2013	$66,652,822
2013/2014	$71,687,937
2014/2015*	$29,045,590
2015/2016	$29,612,591
2016/2017	$27,917,175
2017/2018	$27,419,061
2018/2019**	$97,337,113
Total	$488,251,193

*Start of counter flow "buy back"
**Through December 31, 2018

ARR and FTR Revenue Adequacy

Revenue adequacy for ARRs must be distinguished from the adequacy of ARRs as an offset to total congestion. Revenue adequacy is a narrower and less relevant concept that compares the revenues available to ARR holders to the value of ARRs as determined in the Annual FTR Auction. ARRs have been revenue adequate for every auction to date. Customers that self schedule ARRs as FTRs have the same revenue adequacy characteristics as all other FTRs. ARRs can be revenue adequate at the same time that ARRs return only half of congestion to load.

Total net FTR auction revenue for the 2017/2018 planning period, before accounting for self scheduling, load shifts or residual ARRs, was $573.8 million. The FTR auction revenue collected pays ARR holders' credits. During the first seven months of the 2018/2019 planning period, total net FTR auction revenue was $886.0 million.

Table 13-31 lists projected ARR target allocations from the Annual ARR Allocation and net revenue sources from the Long Term, Annual and Monthly Balance of Planning Period FTR Auctions for the 2017/2018 planning period and the first seven months of the 2018/2019 planning periods. FTRs were paid at 100 percent of the target allocation level for the 2014/2015, 2015/2016 and 2016/2017 planning periods. PJM collected $1,457.1 million, $1,003.3 million and $828.7 million of FTR revenues during the 2014/2015, 2015/2016 and the 2016/2017 planning periods. Congestion in January 2014 was extremely high due to cold weather events, resulting in target allocations and congestion revenues that were unusually high for 2014.

This step change to high levels of FTR revenue adequacy beginning in the 2014/2015 planning period was primarily a result of subjective interventions by PJM to address prior low levels of revenue adequacy.

Table 13-31 presents the PJM FTR revenue detail for the 2017/2018 planning period and the first seven months of the 2018/2019 planning period. In this table, under the new balancing congestion and M2M payment rules, any negative congestion is from day-ahead congestion and does not include balancing congestion. For the 2017/2018 planning period there was $0.5 million and $0.7 million in negative day-ahead congestion in October and November 2017 for a total of $1.2 million in negative day-ahead congestion charged to FTR holders.

Table 13-31 Total annual PJM ARR and FTR revenue detail (Dollars (Millions)): 2017/2018 and 2018/2019

Accounting Element	2017/2018	2018/2019*
ARR information		
ARR target allocations	$573.8	$424.9
ARR credits	$573.8	$424.9
FTR auction revenue	$601.2	$895.2
Annual FTR Auction net revenue	$542.2	$822.6
Long Term FTR Auction net revenue	$18.6	$25.2
Monthly Balance of Planning Period FTR Auction net revenue	$40.3	$47.3
Surplus auction revenue		
ARR excess	$27.4	$97.3
ARR payout ratio	100%	100%
FTR targets		
Positive target allocations	$1,396.2	$770.7
Negative target allocations	($411.2)	($147.2)
FTR target allocations	$985.0	$623.5
Adjustments:		
Adjustments to FTR target allocations	($6.2)	($1.2)
Total FTR targets	$978.8	$622.3
FTR payout ratio	100%	100%
FTR revenues		
ARR excess	$27.4	$97.3
Congestion		
Net Negative Congestion (enter as negative)	($1.2)	$0.0
Hourly congestion revenue	$1,323.3	$557.6
Midwest ISO M2M (credit to PJM minus credit to Midwest ISO)	($6.3)	$0.0
Adjustments:		
Excess revenues carried forward into future months	$15.7	$6.8
Excess revenues distributed back to previous months	$0.0	$0.0
Other adjustments to FTR revenues	$0.0	$0.0
Total FTR revenues		
Excess revenues distributed to other months	$15.7	$6.8
Net Negative Congestion charged to DA Operating Reserves	$0.0	$0.0
Total FTR congestion credits	$1,365.0	$661.7
Total congestion credits on bill (includes CEPSW and end-of-year distribution)	$1,365.0	$661.7
Remaining deficiency	($370.5)	($32.7)

* First seven months of the 2018/2019 planning period

FTR target allocations are based on hourly prices in the Day-Ahead Energy Market for FTR paths and are defined to be the revenue required to compensate FTR holders for the day-ahead CLMP difference on those paths. FTR credits are paid to FTR holders and, depending on market conditions, can be less than the target allocations. Table 13-32 lists the FTR revenues, target allocations, credits, payout ratios, congestion credit deficiencies and excess congestion charges by month. At the end of the 12 month planning period, excess congestion charges are used to offset any monthly congestion credit deficiencies.

The total row in Table 13-32 is not the sum of each of the monthly rows because the monthly rows may include excess revenues carried forward from prior months and excess revenues distributed back from later months. October 2017 had revenue shortfalls totaling $15.6 million, but was fully funded using excess revenue from previous months.

Table 13-32 Monthly FTR accounting summary (Dollars (Millions)): 2017/2018 and 2018/2019

Period	FTR Revenues (with adjustments)	FTR Target Allocations	FTR Payout Ratio (original)	FTR Credits (with adjustments)	FTR Payout Ratio (with adjustments)	Monthly Credits Excess/Deficiency (with adjustments)
Jun-17	$64.8	$60.1	100.0%	$64.8	100.0%	($4.7)
Jul-17	$51.8	$45.4	100.0%	$51.8	100.0%	($6.3)
Aug-17	$35.7	$31.0	100.0%	$35.7	100.0%	($4.7)
Sep-17	$100.5	$93.0	100.0%	$100.5	100.0%	($7.5)
Oct-17	$53.2	$68.8	77.2%	$68.8	100.0%	$15.7
Nov-17	$61.2	$51.0	100.0%	$61.2	100.0%	($10.1)
Dec-17	$142.7	$81.4	100.0%	$142.7	100.0%	($61.3)
Jan-18	$520.2	$268.1	100.0%	$520.2	100.0%	($252.1)
Feb-18	$45.8	$36.1	100.0%	$45.8	100.0%	($9.6)
Mar-18	$85.2	$81.1	100.0%	$85.2	100.0%	($4.1)
Apr-18	$62.4	$55.6	100.0%	$62.4	100.0%	($6.9)
May-18	$125.9	$108.8	100.0%	$125.9	100.0%	($17.1)
Summary for Planning Period 2017/2018						
Total	$1,349.3	$980.5		$1,365.0		($368.8)
Jun-18	$106.8	$96.0	100.0%	$106.8	100.0%	($10.8)
Jul-18	$84.1	$71.3	100.0%	$84.1	100.0%	($12.8)
Aug-18	$84.8	$74.6	100.0%	$84.8	100.0%	($10.2)
Sep-18	$107.3	$102.8	100.0%	$107.3	100.0%	($4.5)
Oct-18	$109.1	$113.8	95.9%	$113.8	100.0%	$4.7
Nov-18	$83.0	$82.5	100.0%	$83.0	100.0%	($0.5)
Dec-18	$79.8	$81.9	97.5%	$81.9	100.0%	$2.1
Summary for Planning Period 2018/2019						
Total	$655.0	$623.0		$661.7		($32.0)

Figure 13-11 shows the original PJM reported FTR payout ratio by month, excluding excess revenue distribution, for January 2004 through December 2018. The months with payout ratios above 100 percent have congestion revenue greater than the target allocations and the months with payout ratios under 100 percent have congestion revenue that is less than the target allocations. Figure 13-11 also shows the payout ratio after distributing surplus congestion revenue across months within the planning period. If there are surplus congestion revenues in a given month, the surplus is distributed to other months within the planning period that were revenue deficient. The payout ratio for revenue inadequate months in the current planning period may change if surplus congestion revenue is collected in the remainder of the planning period. March 2015 had high levels of negative balancing congestion that resulted in a payout ratio of 64.6 percent. However, there was enough surplus from previous months to bring the payout ratio to 100 percent. Congestion in December 2017 and January 2018 was high relative to other months in the planning period, resulting in an extremely high payout ratio.

Figure 13-11 FTR payout ratio by month, excluding and including excess revenue distribution: January 2004 through December 2018

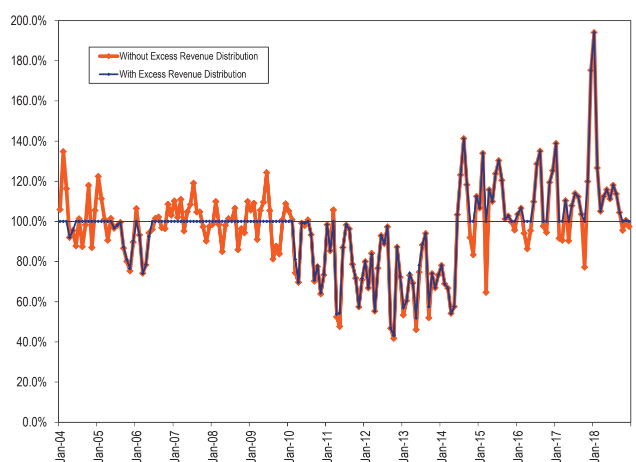


Table 13-33 shows the FTR payout ratio by planning period from the 2003/2004 planning period forward. Planning period 2013/2014 includes the additional revenue from unallocated congestion charges from Balancing Operating Reserves. For the 2014/2015, 2015/2016 and 2016/2017 planning periods, there was surplus congestion revenue to pay FTR holders pro rata in proportion to their net positive target allocations, resulting in a payout ratio of 116.2 percent, 106.8 and 113.1 percent for the planning periods.

Table 13-33 PJM reported FTR payout ratio by planning period

Planning Period	FTR Payout Ratio
2003/2004	97.7%
2004/2005	100.0%
2005/2006	90.7%
2006/2007	100.0%
2007/2008	100.0%
2008/2009	100.0%
2009/2010	96.9%
2010/2011	85.0%
2011/2012	80.6%
2012/2013	67.8%
2013/2014	72.8%
2014/2015	100.0%
2015/2016	100.0%
2016/2017	100.0%
2017/2018	100.0%
2018/2019	100.0%

FTR Uplift Charge

At the end of the planning period, an uplift charge may be assigned to FTR holders. This charge is to cover the net of the monthly deficiencies, if any, in the target allocations calculated for individual participants. An individual participant's uplift charge is a ratio of their share of net positive target allocations to the total net positive target allocations.

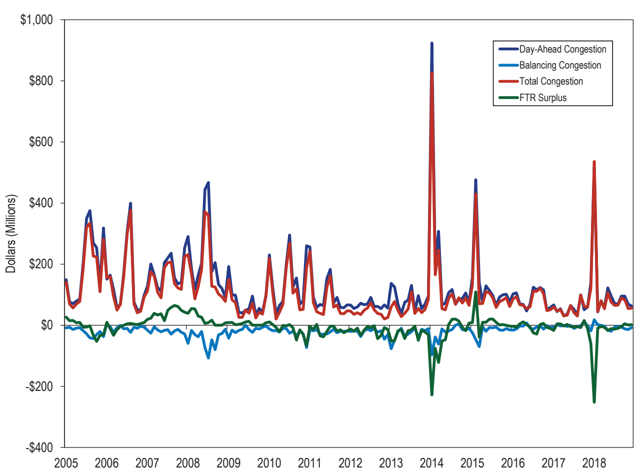
Revenue Adequacy Issues and Solutions

The current ARR/FTR design does not serve as an efficient way to ensure that load receives all the congestion revenues or has the ability to receive the auction revenues associated with all the potential congestion revenues. There are several reasons for the disconnect between congestion revenues and ARR/FTR revenues. The reasons include unavoidable modeling differences, such as emergency outages, avoidable modeling differences, such as outage modeling decisions, cross subsidies among and between FTR participants ARR holders, the use of generation to load paths rather than a measure of total congestion, and the failure to provide to ARR holders the full system capability that is provided to FTR purchasers in the Long Term FTR Auction.

The issuance of the September 15, 2016, FERC order increased the gap between congestion revenue and ARR/FTR revenue collected. The result of allocating balancing congestion and M2M payments to ARRs, and allocating surplus congestion revenue, which contains excess day-ahead congestion revenue and additional FTR auction revenue, to FTR holders solely, increased revenue to FTRs and reduced payments to load. Under the new rules, effective for the 2018/2019 planning period, ARR holders receive the surplus congestion revenue, but must still pay balancing congestion to help FTR holders' revenue adequacy. FTR portfolio netting leads to cross subsidies among FTR participants which treat FTRs differently depending on how a participant's portfolio in constructed. Restructuring Stage 1A allocations using QRRs for retired resources is an attempt to fix a flawed system, but retains the core problem which is reliance on generation to load contract path congestion revenue rights rather than on the correct definition of congestion revenues. The rule change does not address the problem with using contract paths, does not address the deficiencies for active units and gives priority to units based on financial, not physical, determinations. The purpose of the FTR/ARR system is to return congestion revenue to load. The current and newly modified rules do not meet this goal.[45]

Figure 13-12 shows the FTR surplus, collected day-ahead, balancing and total congestion payments from January 2005 through December 2018. May 2016 had positive total balancing congestion of $7.5 million. March 2015 had balancing congestion of -$70.0 million.

Figure 13-12 FTR surplus and the collected day-ahead, balancing and total congestion: January 2005 through December 2018



45 *2017 State of the Market Report for PJM*, Vol., Section 13: FTRs and ARRs.

ARRs as an Offset to Congestion for Load

Load pays for the transmission system and pays congestion revenues. FTRs and later ARRs were intended to return congestion revenues to load. With the implementation of the current FTR/ARR design, the purpose of FTRs has been subverted.

Zonal ARR Congestion Offset

ARRs are allocated based on zonal base and peak loads on historical generation to load pathways. However, ARR revenue is not directly linked to the congestion paid within a zone. ARR revenue comes from the sale of FTRs. ARR revenue for a zone is calculated as revenues received by ARRs that sink in that zone. Congestion paid by load in a zone is the total difference between what the zonal load pays in congestion charges net of what the generation that serves that load is paid. The definition of zonal congestion is on a constraint by constraint basis for each zone.[46]

FERC Order on FTRs: Balancing Congestion and M2M Payment Allocation

On September 15, 2016, FERC issued an order removing balancing congestion and market to market (M2M) payments from the FTR funding equation and assigned them, on a load ratio basis, to load and exports.[47] The MMU petitioned the U.S. Court of Appeals for the District of Columbia Circuit to reverse the order and restore the longstanding approach to calculating congestion revenues. The case was consolidated with appeals filed by others. The consolidated appeals were denied in an unpublished opinion issued June 12, 2018.[48]

The new rule for calculating congestion revenues went into effect on June 1, 2017, for the 2017/2018 planning period.

In its compliance filing PJM redefined balancing congestion as balancing congestion plus market to market (M2M) payments between MISO and NYISO. Under the order, load and exports will pay balancing congestion and M2M payments proportionally. Based on the 2011/2012 and subsequent planning periods, load comprises 94.9 percent of all demand. Based on the 2011/2012 and subsequent planning periods, total balancing congestion and M2M payments were $1,607.4 million, so load would have been responsible for an additional $1,103.3 million in balancing congestion and M2M charges if the new rules had been place for that period.

In addition, FERC ordered that all day-ahead congestion revenue in excess of FTR target allocations and additional FTR auction revenue over ARR target allocations, belongs to FTR holders. This further increased the underlying problem with the FTR design and reduced the probability that congestion revenues will be returned to load.

Before the 2018/2019 planning period, the reallocation of balancing congestion and M2M payments from FTR holders to load, and the allocation of additional FTR auction revenues to FTR holders required ARRs to subsidize FTRs.

Beginning with the 2018/2019 planning period, surplus congestion revenue, which is defined as day-ahead congestion revenue and surplus auction revenue remaining after funding FTRs, will be allocated to ARRs prorata based on ARR target allocations.[49]

This surplus revenue is generated by a failure of the current ARR/FTR construct to make all congestion revenue rights available to load in the form of ARRs. All congestion revenue belongs to ARR holders and PJM's new surplus congestion allocation rule is an attempt to get closer to that goal. However, under the current rules, ARR holders will only have access to this surplus after full funding of FTRs is accomplished, which does not fully recognize ARR holders' primary rights to this surplus congestion revenue. If this rule had been in effect for the 2017/2018 planning period, ARRs and FTRs would have offset 74.3 percent of total congestion rather than 50.0 percent.

Table 13-34 shows the ARR and FTR revenue paid to load, the congestion offset available to load with and

46 See *2018 State of the Market Report for PJM*, Section 11: Congestion and Marginal Losses

47 See 156 FERC ¶ 61,180 (2016), *reh'g denied*, 156 FERC ¶ 61,093 (2017).

48 *NJBPU v. FERC*, No. 17-1106 et al., attached memorandum at 3 ("After a thorough review of the record, we conclude that none of petitioners' challenges can overcome the deference we owe FERC. As FERC's order make clear, the Commission adequately considered and reasonably rejected each of the arguments that petitioners advance before the court.")

49 163 FERC ¶61,165 (2018).

without allocating balancing congestion to load and the congestion offset when surplus congestion revenue is allocated to load. The offset for the current 2018/2019 planning period is estimated based on distribution of the surplus revenue to ARR holders as of the end of December 2018. The pre 2017/2018 offset is calculated as the ARR credits and the FTR credits excluding balancing congestion and M2M payments, divided by the total congestion and the load share of balancing and M2M payments. The 2017/2018 offset is the sum of the ARR credits, adjusted FTR credits and the load share of balancing congestion and M2M payments. The post 2017/2018 offset is calculated identically to the 2017/2018 offset, but includes any surplus congestion revenue remaining in the planning period. FTRs are fully funded before ARR holders have access to the surplus, so in planning periods with revenue inadequacy there is no difference between 2017/2018 and post 2017/2018. In planning periods that are fully funded, the surplus goes to load, and provides an increased congestion offset.

The allocation of balancing congestion and M2M payments to load went into effect in the 2017/2018 planning period. If these rules had been in place beginning with the 2011/2012 planning period, ARR holders would have received a total of $1,034.2 million less in congestion offsets from the 2011/2012 through the 2016/2017 planning period. The total overpayment to FTR holders for the 2011/2012 through 2016/2017 planning period would have been $944.4 million. The actual underpayment to load in the 2017/2018 planning period was $125.8 million with a $370.7 million overpayment to FTR holders. If the surplus congestion from the first seven months of the 2018/2019 planning period were allocated to load, the underpayment to load in the same period would have been $103.2 million.

Allocating surplus congestion revenue to load rather than FTRs in the first seven months of the 2018/2019 planning period would change the total congestion offset for load to 74.2 percent from 89.1 percent under the old rules or 71.1 percent under the rules that allocated balancing congestion to load.

Table 13-34 ARR and FTR total congestion offset (in millions) for ARR holders: 2011/2012 through 2018/2019

	Revenue				Pre 2017/2018 (Without Balancing)		2017/2018 (With Balancing)		Post 2017/2018 (With Surplus)	
Planning Period	ARR Credits	FTR Credits	Total Congestion	Excess Revenue	Total ARR/ FTR Offset	Percent Offset	Current Revenue Received	Percent Offset	New Revenue Received	New Offset
2011/2012	$512.2	$249.8	$749.7	($192.5)	$762.0	100.0%	$598.6	79.8%	$563.0	79.8%
2012/2013	$349.5	$181.9	$524.8	($292.3)	$531.4	100.0%	$275.9	52.6%	$257.5	52.6%
2013/2014	$337.7	$456.4	$1,870.6	($678.7)	$794.0	42.4%	$574.1	30.7%	$623.1	30.7%
2014/2015	$482.4	$404.4	$1,357.6	$139.6	$886.8	65.3%	$686.6	50.6%	$715.0	52.7%
2015/2016	$635.3	$223.4	$951.1	$42.5	$858.8	90.3%	$744.8	78.3%	$745.2	78.4%
2016/2017	$640.0	$169.1	$780.8	$72.6	$809.1	100.0%	$727.7	93.2%	$763.8	97.8%
2017/2018	$427.3	$294.2	$1,192.6	$371.2	$721.5	60.5%	$595.7	50.0%	$886.5	74.3%
2018/2019*	$308.9	$91.3	$468.8	$32.5	$417.76	89.1%	$333.1	71.1%	$348.0	74.2%
Total	$3,693.4	$2,070.4	$7,896.0	($505.2)	$5,781.3	73.2%	$4,536.7	57.5%	$4,902.2	62.1%

* Seven months of 2018/2019 planning period

Table 13-34 demonstrates the inadequacies of the ARR/FTR design. The goal of the design should be to return 100 percent of the congestion revenues to the load. The actual results continue to fall well short of that goal.

Table 13-35 shows the ARR and FTR offset for ARR holders that was actually effective given the active rules at the time of the planning period. The 100 percent payout ratio in the 2016/2017 planning period, which was the last planning period before balancing congestion was assigned to load, is likely due to PJM selecting an overly conservative ARR/FTR model to improve FTR revenue adequacy.

Table 13-35 ARR and FTR actual total congestion offset for ARR holders

Planning Period	Total Offset
2011/2012	100.0%
2012/2013	100.0%
2013/2014	42.4%
2014/2015	65.3%
2015/2016	90.3%
2016/2017	100.0%
2017/2018	50.0%
2018/2019*	74.2%

* Seven months of 2018/2019

Credit

On June 21, 2018, GreenHat Energy, LLC was declared in default for two collateral calls totaling $2.8 million and two payment defaults totaling $3.9 million.[50] There were 14 collateral defaults in 2018 not involving GreenHat Energy, LLC, for a total of $643,371. Most collateral defaults were cured promptly. There were 74 payment defaults in 2018 not involving GreenHat Energy, LLC for a total of $136,120. Amerigreen Energy, Inc. defaulted on June 12, 2018.[51]

Modified Credit Requirements

PJM has modified its credit requirements following the GreenHat Energy default.

On December 11, 2017, PJM filed, and FERC accepted, a modification to the credit rules for the Long Term FTR Auction.[52] Credit requirements are based on a calculation of the expected FTR values relative to the price of FTRs. Under the prior rules, PJM calculated the expected FTR value was based on a three year weighted average of nodal prices. The method was based solely on historical data, and did not account for transmission upgrades that would affect congestion and therefore FTR values. Under the new rules, PJM calculates the FTR credit requirement using the higher of: the expected FTR value based on a three year weighted average of the previous three year's nodal prices; and the expected FTR value based on a planning model simulation of expected congestion given transmission upgrades over the next year (the adjusted historical value).

The new approach to calculating the expected value of FTRs is only used for one year, including the YR1 long term FTR. PJM's modeling change does not address the same credit risk for YR2 and YR3 of LTFTRs. PJM continues to use the old method of calculating expected FTR values for YR2 and Y3 of LTFTRs.

On July 27, 2018, PJM filed, and FERC accepted, a modification to the credit rules for the FTR Market.[53] The update puts a volumetric credit requirement of $0.10 per MWh on participants' FTR portfolios.

On January 31, 2019, PJM filed a modification to the credit rules that would allow PJM to update the credit requirements for already acquired FTRs.[54] PJM terms this proposal: mark to auction. Under the current rules PJM cannot issue a collateral call within an FTR's effective period. Under the proposed mark to auction rules PJM could calculate the credit requirement based on the most recent auction price and make any required collateral calls.

PJM's proposed new credit policy incorporates all of these changes. The final credit requirement is the higher of the historical weighted value, the adjusted historical weighted value, the volumetric requirement or the mark to auction requirement. If, during the planning period, the mark to auction requirement is higher than the current credit requirement, the mark to auction credit requirement is adopted.

GreenHat Energy, LLC Default

On June 21, 2018, GreenHat Energy, LLC was declared in payment default for non-payment of a $1.2 million weekly invoice on June 5, 2018. GreenHat had been declared in default twice earlier in June 2018 for two collateral calls totaling $2.8 million.[55]

GreenHat held a large FTR position which, according to the tariff provisions effective in June 2018, must be liquidated in the FTR auctions closest to the effective dates of the positions held.[56] The net gain or loss on these liquidated positions is added to the payment default amount that will then be allocated to PJM members according to OA sections 15.1.2A(1) and 15.2.2.

50 Daugherty, Suzanne, Email sent to the MC, MRC, CS, and MSS email distribution list, "Notification of GreenHat Energy, LLC Payment Default," (June 22, 2018).

51 Daugherty, Suzanne, Email sent to the MC, MRC, CS, and MSS email distribution list, "PJM Member Default – Amerigreen Energy, Inc.," (June 13, 2018).

52 See Docket No. ER18-425.

53 164 FERC ¶ 61,215 (2018).

54 *See* "PJM Interconnection, LLC Revisions to PJM Tariff to Incorporate FTR Mark-to-Auction Provisions," Docket No. ER19-945 (January 31, 2019).

55 Daugherty, Suzanne, email sent to the MC, MRC, CS, and MSS email distribution list, "Notification of GreenHat Energy, LLC Payment Default," (June 22, 2018).

56 "PJM Manual 6: Financial Transmission Rights," Rev. 21 (Dec. 6, 2018) .

GreenHat's FTR initial portfolio was primarily long term FTRs, many of which were counterflow, although GreenHat subsequently purchased annual FTRs to offset their credit requirements. Liquidation of the counterflow positions would require payment to the acquiring party an amount equal to the expected value of the counterflow FTR position, plus a risk premium plus a profit. Given the size of GreenHat's portfolio, liquidation was expected to have a significant effect on FTR market prices in any months where liquidation occurred and result in significant payments by PJM members.

On July 26, 2018, PJM filed a request with FERC for a waiver of the tariff provision requiring immediate liquidation of a defaulted FTR position.[57]

Between the default date and the filing of the waiver, one monthly FTR auction occurred for August 2018. In this auction, PJM was required, by existing tariff provisions, to liquidate GreenHat's prompt month FTR positions. The result of this liquidation of prompt month August FTRs was $24.1 million in costs charged to the default allocation assessment.

Consistent with the waiver request, in September 2018, Members elected to settle GreenHat's FTR portfolio at the time the FTRs are due, rather than liquidate them, so default allocation assessment charges would continue to accrue on GreenHat's defaulted FTR portfolio through May 2021.

On January 30, 2019, FECR denied PJM's request for a waiver. The result of the waiver denial is that PJM must unwind the results of the auctions it ran based on its expectation of receiving a waiver. PJM has estimated that market participants could be required to pay $250 to $300 million to resolve GreenHat's defaulted FTRs.[58]

PJM filed, and FERC accepted a tariff revision that replaces the rule requiring immediate liquidation.[59] Under the new rule FTRs within a defaulted participant's portfolio will settle, as do all FTRs, at the hourly day-ahead value. Any positive or negative target allocations will then be credited or charged to the default allocation assessment. The default allocation assessment is charged to all PJM participants in proportion to their gross bill as the assessment is calculated monthly for the duration of the defaulted positions. The final amount of payments is not known until the end of the term of all the defaulted FTRs.

As an alternative to the PJM proposal, the MMU recommended the cancellation of defaulted FTRs, which would have a fixed impact within the FTR market alone, and would not have extended the potential impacts past the current planning period.

GreenHat Energy Default Lessons Learned

On August 14, 2018, PJM hosted an FTR risk management workshop whose participants included experts in energy market and risk management in addition to PJM and the MMU.[60] The objective of this workshop was to examine the credit policies of the FTR market and develop suggestions for enhancements in light of the Green Hat default.

The recommendations of members of the group directly related to credit issues included: increased participation requirements; PJM discretion to make collateral calls; position limits; creation of a liquidity margin in credit requirements; limitations on credit netting for prevailing flow and counter flow positions; volatility adder to credit requirements; transfer risk management to an external authority.

The recommendations of members of the group related to relevant market design issues included: eliminate long term FTRs; revise the eligible FTR bidding points; remove at risk generators from the FTR model; and hold more frequent FTR auctions.

Bilateral Indemnification Provisions

The purchaser of an FTR in an auction may sell the FTR to a third party buyer in a bilateral transaction. PJM's credit rules included a bilateral indemnification provision that requires the seller of the FTR to pay any charges if the buyer defaults. PJM interprets the indemnification provision to make the seller solely responsible for only the charges on the FTR without receiving any of the associated credits. For example, even if the portfolio of

57 See 166 FERC ¶ 61,072, *reh'g pending.*

58 *See* Presentation "Update on FERC Order Denying PJM's Request for Waiver re: Liquidating FTR Positions of Defaulted Member," MRC. February 21, 2019.

59 See Letter Order, FERC Docket No. ER18-2289-000 (October 19, 2018).

60 *See* "PJM Financial Transmission Right (FTR) Risk Management Workshop" Credit Subcommittee, September 17, 2018.

FTRs held by the buyer is net positive, the seller must still pay all charges associated with those FTRs.[61]

By failing to net the indemnification obligation within the full portfolio of FTRs sold in a bilateral transaction, PJM's current interpretation of the rule goes beyond having the seller indemnify PJM against losses associated with a bilateral trade with the defaulting buyer. PJM's interpretation of the indemnification rule requires that the seller pay any charges associated with the bilateral FTRs, regardless of the net value of the portfolio of bilateral FTRs. Even if the value of the portfolio of bilateral FTRs is net positive, the seller still pays any charges associated with any individual FTRs in that portfolio. This means that PJM is requiring the seller to indemnify PJM against charges over and above those incurred by the relevant bilaterally traded FTRs.

Under this interpretation, bilateral sellers are held to stricter credit rules than other holders of FTRs because they must guarantee more than the net amount of FTR credits for that portfolio. The requirements and obligations associated with selling an FTR should be the same regardless of how the FTR was sold.

PJM must approve every bilateral transaction. There is no reason a bilateral sale should be held to different standards than a sale within an FTR auction. If the implemented credit rules are sufficient there is no need for an indemnification provision. If the credit rules are not sufficient to protect participants from bilateral transfer risk, then bilateral transactions should be eliminated.

The indemnification rule should be modified so that the indemnifying seller was responsible for the net charges associated with the FTRs it sold to a buyer and this would still eliminate socialized default charges associated with the bilateral arrangement between the seller and the buyer. PJM's proposal to allow the indemnifying seller a onetime option to assume ownership of the negative bilateral FTRs could be modified to allow the seller to acquire all the FTRs the seller sold to the defaulting buyer. With this modification, no snap shot determination of the relative value of the FTRs is needed. In terms of socialized costs to the membership, this change in the rules and proposal would eliminate the inconsistency in the indemnification by bilateral and auction transactions.

61 For a more complete discussion, see: "Answer and Motion for Leave to Answer of the Independent Market Monitor for PJM," Docket No. ER19-24 (November 27, 2018).

FTR Forfeitures

Hourly FTR Cost

Only the profit is forfeited when an FTR triggers the FTR forfeiture rule. The profit is calculated as the hourly FTR target allocation minus the FTR's hourly cost. Under the current rules, the hourly cost is calculated incorrectly. Currently, the daily cost of an FTR is calculated for its effective period, and then divided by 24 hours. However, this does not accurately represent the hourly cost of on and off peak FTRs. The correct way to calculate the hourly cost of an FTR is to calculate its cost for the effective period only for hours in which it is effective.

FERC Order on FTR Forfeitures

On January 19, 2017, FERC determined that the application of the current FTR forfeiture rule to INCs, DECs and UTCs was unjust and unreasonable.[62] In their determination, FERC ordered that a method should be developed to consider the net impact of a participant's entire portfolio of virtual bids on a constraint related to an FTR position and ordered that counter flow FTRs be included in FTR forfeiture calculations.

FERC ordered a retroactive effective date meaning that participants would be retroactively billed their FTR forfeiture amounts based on the new FTR forfeiture rule once it was in place.

Until January 19, 2017, an FTR holder was subject to forfeiture of any profits from an FTR if it met the criteria defined in Section 5.2.1(b) of Schedule 1 of the OA. If a participant has a cleared increment offer or decrement bid for an applicable hour at or near the source or sink of any FTR they own and the day-ahead congestion LMP difference is greater than the real-time congestion LMP difference the profits from that FTR may be subject to forfeiture for that hour. An increment offer or decrement bid is considered near the source or sink point if 75 percent or more of the energy injected or withdrawn, and which is withdrawn or injected at any other bus, is reflected on the constrained path between the FTR source or sink. This rule only applies to increment offers and

62 See 158 FERC ¶ 61,038.

decrement bids that would increase the price separation between the FTR source and sink points.

After January 19, 2017, participants were subject to the new FTR forfeiture rule. This rule considers the impact of a participant's net virtual transaction portfolio on all constraints. If a participant's net virtual portfolio impacts a constraint by the greater of 0.1 MW or 10 percent or more of the line limit, and that constraint affects an individual FTR's target allocation by $0.01, the FTR is subject to FTR forfeiture if the net virtual portfolio increased the value of the FTR. FTR forfeitures do not result from net virtual portfolios that decrease the value of their affiliates' FTRs. The forfeiture amount calculation is the hourly profit of the FTR and an FTR cannot forfeit more than once per hour.

Figure 13-13 shows the monthly FTR forfeitures under the newly established FTR forfeiture rule from January 19, 2017 through December 31, 2018, except for November 2018 which is not yet settled. PJM began retroactively billing FTR forfeitures with the September 2017 bill. In the interim period from January 2017 through September 2017 participants did not know what behaviors were causing FTR forfeitures, so they had no way to modify their bidding behavior to avoid FTR forfeitures. After September 2017, FTR forfeitures were down significantly, and stabilized, as participants could now see the effect of their activities on FTR forfeitures. For the period of January 19, 2017, through December 31, 2018, except November 2018, total FTR forfeitures were $13.1 million.

Figure 13-13 Monthly FTR forfeitures for physical and financial participants